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Tennessee Valley Authority, Muscle Shoals, AL

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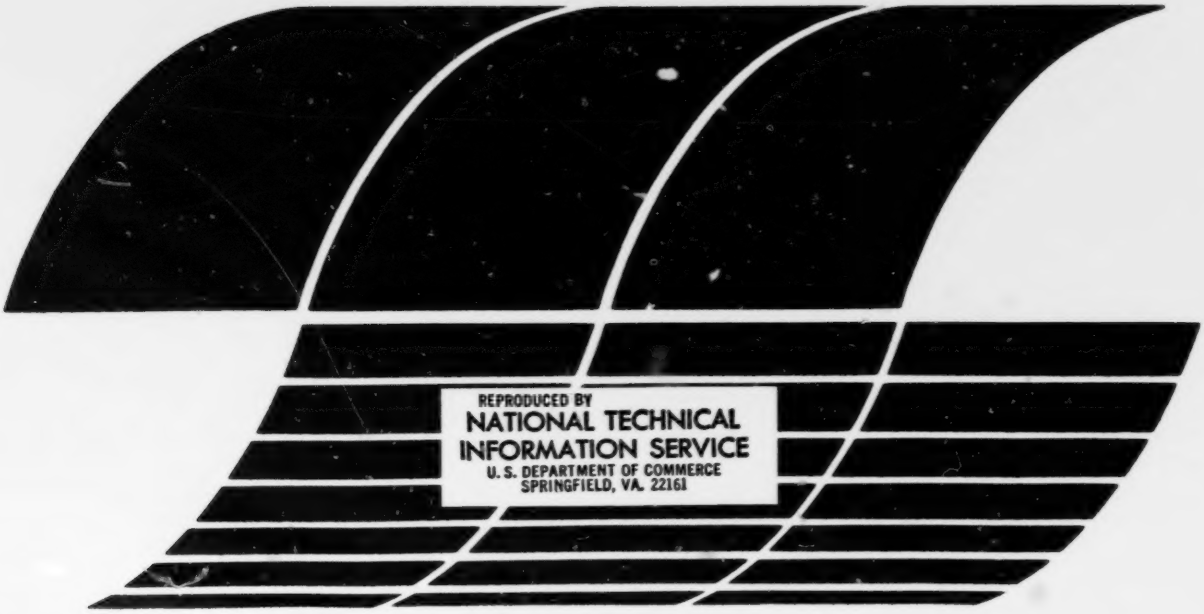
Interagency Energy/Environment R&D Program Report



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Evaluation	Limestone	Stationary Sources	14B	08G
Coal	Slurries	Double Alkali Process	21D	11G
Combustion	Citrates	Trucking	21B	07C
Flue Gases	Waste Disposal			
Desulfurization	Ponds		07A, 07D	08H

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DEFINITIVE SO_x CONTROL PROCESS EVALUATIONS

LIMESTONE, DOUBLE-ALKALI, AND CITRATE FGD PROCESSES

by

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ABSTRACT

A detailed comparative technical and economic evaluation of limestone slurry, generic double alkali, and citrate flue gas desulfurization (FGD) processes was made assuming proven technology and using representative power plant, process design, and economic premises. For each process, economic projections were made for a base case (500 MW, 3.5% sulfur in coal, new unit) and case variations in power unit size, fuel type, sulfur in fuel, new and existing power units, waste slurry ponding and filter cake trucking, and sulfur dioxide (SO_2) removal (1.2 lb SO_2 allowable emission per million Btu heat input vs 90%). Capital investment, annual revenue requirements (7000 hr/yr), and lifetime revenue requirements over a 30-year declining operating profile were estimated for the base case and each variation. Investment costs were projected to mid-1979; annual revenue requirements were calculated in projected mid-1980 dollars. Effects of variations in raw material costs, energy costs, maintenance costs, cost of capital, and net sales revenue and operating labor cost escalation were studied.

Depending on unit size and status, fuel type and sulfur content, solids disposal method, and overall project scope, the ranges in estimated capital costs in 1979 dollars are \$71 to \$127/kW for limestone slurry, \$80 to \$130/kW for generic double alkali, and \$105 to \$194/kW for citrate (recovery process). The results can be scaled or altered to reflect other site-specific conditions.

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ABBREVIATIONS AND CONVERSION FACTORS

ABBREVIATIONS

ac	acre
aft^3/min	actual cubic feet per minute
bbl	barrel
Btu	British thermal unit
^{o}F	degrees Fahrenheit
dia	diameter
FGD	flue gas desulfurization
ft	feet
ft^2	square feet
ft^3	cubic feet
gal	gallon
gpm	gallons per minute
gr	grain
hp	horsepower
hr	hour
in.	inch
k	thousand
kW	kilowatt
kWh	kilowatt-hour
lb	pound
L/G	liquid-to-gas ratio in gallons per thousand actual cubic feet of gas at outlet conditions
M	million
mi	mile
mo	month
MW	megawatt
ppm	parts per million
psig	pounds per square inch (gauge)
rpm	revolutions per minute
sec	second
sft^3/min	standard cubic feet per minute (60^{o}F)
SS	stainless steel
yr	year

CONVERSION FACTORS

EPA policy is to express all measurements in Agency documents in metric units. Values in this report are given in British units for the convenience of engineers and other scientists accustomed to using the British systems. The following conversion factors may be used to provide metric equivalents.

British			Metric	
ac	acre	0.405	hectare	ha
bbl	barrels of oil[a]	158.97	liters	ℓ
Btu	British thermal unit	0.252	kilocalories	kcal
°F	degrees Fahrenheit minus 32	0.5556	degrees Celsius	°C
ft	feet	30.48	centimeters	cm
ft^2	square feet	0.0929	square meters	m^2
ft^3	cubic feet	0.02832	cubic meters	m^3
ft/min	feet per minute	0.508	centimeters per second	cm/sec
ft^3/min	cubic feet per minute	0.000472	cubic meters per second	m^3/sec
gal	gallons (U.S.)	3.785	liters	ℓ
gpm	gallons per minute	0.06308	liters per second	ℓ/sec
gr	grains	0.0648	grams	g
gr/ft^3	grains per cubic foot	2.288	grams per cubic meter	g/m^3
hp	horsepower	0.746	kilowatts	kW
in.	inches	2.54	centimeters	cm
lb	pounds	0.4536	kilograms	kg
lb/ft^3	pounds per cubic foot	16.02	kilograms per cubic meter	kg/m^3
lb/hr	pounds per hour	0.126	grams per second	g/sec
psi	pounds per square inch	6895	Pascals (Newton per square meter)	pa (N/m^2)
mi	miles	1609	meters	m
rpm	revolutions per minute	0.1047	radians per second	rad/sec
sft^3/min	standard cubic feet per minute (60°F)	1.6077	normal cubic meters per hour (0°C)	Nm^3/hr
ton	tons (short)[b]	0.9072	metric tons	tonne
ton, long	tons (long)[b]	1.016	metric tons	tonne
ton/hr	tons per hour	0.252	kilograms per second	kg/sec

---

a. Forty-two U.S. gallons per barrel of oil.
b. All tons, including tons of sulfur, are expressed in short tons in this report.

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DEFINITIVE SO_x CONTROL PROCESS EVALUATIONS - PHASE I

EXECUTIVE SUMMARY

Under the provisions of the Clean Air Act of 1967 and its subsequent amendments, the U.S. Environmental Protection Agency (EPA) has funded research and development on sulfur dioxide (SO_2) removal processes, including the publication of several conceptual design and cost studies. This report is one of a series of flue gas desulfurization (FGD) studies sponsored by EPA to determine comparative costs of some of the more prominent SO_2 removal systems now being offered by vendors. Three processes are evaluated in this report--limestone slurry, generic double alkali, and citrate scrubbing. Process evaluations in subsequent studies will include lime scrubbing, magnesia scrubbing, the Wellman-Lord sodium sulfite process, and the Rockwell International aqueous carbonate process.

PROCESS DEFINITION

A brief description of the three processes in this study and the data sources used as the basis are given below. The process data represent the state of technology in late 1977.

Representative flow diagrams, material balances, plant layouts, and equipment arrangements are included in the report for the base case (new 500-MW coal-fired unit, 3.5% sulfur in fuel, 1.2 lb SO_2 emission per million Btu heat input) of each process. These and detailed equipment descriptions define the systems estimated.

Limestone Slurry Process

Stack gas is scrubbed with a recirculating slurry of limestone and reacted calcium salts in water (pH about 5.8) using a presaturator unit for cooling and humidification and a mobile-bed scrubber for SO_2 removal. Limestone feed is wet-ground prior to addition to the scrubber effluent hold tank. Calcium sulfite and sulfate salts are withdrawn to a disposal pond where they settle to a 40% solids sludge. Cleaned stack gas is reheated to 175°F. Design is based on data taken from the TVA-EPA-Bechtel Shawnee test program and TVA Widows Creek unit 8.

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Generic Double-Alkali Process

Stack gas is cooled and humidified in a presaturator using recycled scrubber effluent and scrubbed in a perforated-plate scrubber with regenerated sodium sulfite(pH about 6.0). A bleedstream of scrubber effluent is reacted with lime to regenerate sodium sulfite and produce calcium sulfite and sulfate salts. After filtering and washing to recover the sodium sulfite solution, the calcium sulfite-sulfate cake is reslurried and pumped to the disposal pond where the salts settle to 40% solids. Makeup soda ash is added at the thickener overflow tank. Cleaned stack gas is reheated to 175°F. The double-alkali design is generalized from several processes currently offered in the United States.

Citrate Process

Stack gas is cooled and humidified in a presaturator using recycled liquor and scrubbed in a packed-tower scrubber with regenerated citrate solution (pH about 4.5). A bleedstream of presaturator recycle liquor is neutralized with lime and discarded to control chlorides in the system. Scrubber effluent is reacted with hydrogen sulfide (H_2S) to produce elemental sulfur and regenerate the citrate scrubbing solution. Sulfur is separated by air flotation, melted, and stored in liquid form to be sold. Part of the sulfur is combined with natural gas and steam to form H_2S for use in the reduction process. Makeup soda ash and citric acid are added to replace losses due to handling and oxidation of sulfite to sulfate. Sodium sulfate crystals are purged from the system and discarded. Cleaned stack gas is reheated to 175°F. Conceptual design for the generalized citrate process is based primarily on the U.S. Bureau of Mines system. Design differences in the Bureau of Mines demonstration unit have been noted.

MAJOR DESIGN AND COST FACTORS

The base case for evaluating the three processes is a new, 500-MW, coal-fired power unit located in the Midwest (Illinois, Indiana, Kentucky area). The project schedule begins in mid-1977 with a 3-year construction period ending mid-1980. The midpoint of construction costs is mid-1979; revenue requirements are estimated in mid-1980 dollars.

Other important design and cost assumptions used in the evaluations are:

- The coal has a heating value of 10,500 Btu/lb and contains 16% ash.
- SO_2 removal reduces emissions to 1.2 lb SO_2 per million Btu heat input.
- Stack gas is reheated to 175°F.
- Both ponding and trucking disposal at a site 1 mile from the FGD facilities are evaluated for the limestone and double-alkali processes. Thirty-day storage and a base value of $40 per short ton for sulfur have been used for the citrate process.

- The use of a fully developed design is assumed. No redundancy is included; only spare pumps are included. A second pond transport line is included in disposal cases. An orderly and well-managed design and construction program is assumed.

- Revenue requirements are estimated on 7,000-hour annual operation.

RESULTS

Summaries of capital investment, annual revenue requirements, and lifetime operating costs for all cases estimated are displayed in Tables S-1, S-2, and S-3, respectively.

Capital Investment

In order of increasing investment, the base case process ranking is (1) limestone slurry, (2) generic double alkali, and (3) citrate.

Except for the waste-disposal-by-trucking cases, limestone has the lowest capital investment and citrate has the highest for each variation. The limestone trucking alternative capital investment is 2.4% higher than the double-alkali case because limestone FGD produces more waste solids and requires a larger investment in the feed preparation area.

Capital investment for the existing power unit variation is greater than the new power unit variation at each plant size with the exception of the limestone 200-MW cases. For the existing limestone 200-MW unit the decrease in cost due to decrease in pond size based on a remaining life of 20 years slightly outweighs the increase in labor charges required for retrofit.

SO_2 removal of 90% compared with SO_2 removal equal to 1.2 lb SO_2 emission per million Btu heat input increases base case capital investment by 3.5% to 4.2%.

Base case projections described here represent a proven FGD system designed with no redundancy and operating at minimum required removal capacity on flue gas from 3.5% sulfur coal. As an indication of how the project scope and corresponding investment could vary, the effects of changes in process design and indirect charges on the limestone base case estimate are shown in Table S-4. Changes such as 50% redundancy, 90% SO_2 removal. 6% sulfur in coal, increased stoichiometry, greater entrainment in the cleaned gas, and a larger contingency charge can double the investment requirement for the limestone slurry process. Similar effects on investment needs can be expected in the double-alkali and citrate processes with changes in project scope.

TABLE S-1. SUMMARY OF TOTAL CAPITAL INVESTMENT REQUIREMENTS[a,b]

Case	Years remaining life	Limestone process		Generic double-alkali process		Citrate process	
		Total capital investment, $	$/kW	Total capital investment, $	$/kW	Total capital investment, $	$/kW
Coal-Fired Power Unit							
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)							
200 MW E 3.5% sulfur	20	25,057,000	125.3	26,006,000	130.0	38,788,000	193.9
200 MW N 3.5% sulfur	30	25,461,000	127.3	25,477,000	127.4	38,075,000	190.9
500 MW E 3.5% sulfur	25	50,120,000	100.2	53,675,000	107.4	72,605,000	145.2
500 MW N 2.0% sulfur	30	39,641,000	79.3	42,110,000	84.2	58,098,000	116.2
500 MW N 3.5% sulfur	30	48,728,000	97.5	50,551,000	101.1	71,639,000	143.3
500 MW N 5.0% sulfur	30	54,621,000	109.2	57,579,000	115.2	82,572,000	165.1
1,000 MW E 3.5% sulfur	25	74,830,000	74.8	85,487,000	85.5	109,024,000	109.0
1,000 MW N 3.5% sulfur	30	71,423,000	71.4	79,016,000	79.0	106,589,000	106.6
Solids disposal by trucking							
500 MW N 3.5% sulfur	30	42,307,000	84.6	41,335,000	82.7	-	-
90% SO_2 removal; onsite solids disposal (ponding)							
500 MW N 3.5% sulfur	30	50,437,000	100.9	52,404,000	104.8	74,624,000	149.2
Oil-Fired Power Unit							
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)							
500 MW E 2.5% sulfur	25	38,480,000	77.0	40,260,000	80.5	52,442,000	104.9

a. Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979. Minimum in-process storage; only pumps are spared. Disposal area located 1 mile from power plant. Investment requirements for fly ash removal and disposal excluded. Construction labor shortages with accompanying overtime pay incentive not considered.

b. These investment costs are characterized by the defined premises and assumptions. Modifying the project scope of the limestone process as shown in Table S-4 can increase system costs by $96/kW or more depending on the assumptions made.

TABLE S-2. SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS

(INCLUDING BYPRODUCT CREDIT)

Case	Years remaining life	Limestone process		Generic double-alkali process		Citrate process	
		Average annual revenue requirements, $	Mills/kWh	Average annual revenue requirements, $	Mills/kWh	Average annual revenue requirements, $	Mills/kWh
Coal-Fired Power Unit							
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)							
200 MW E 3.5% sulfur	20	7,479,400	5.34	7,553,000	5.40	12,289,200	8.78
200 MW N 3.5% sulfur	30	7,153,200	5.11	7,169,100	5.12	11,670,800	8.34
500 MW E 3.5% sulfur	25	14,789,400	4.23	15,441,700	4.41	23,174,000	6.62
500 MW N 2.0% sulfur	30	11,624,900	3.32	11,335,300	3.24	17,091,700	4.88
500 MW N 3.5% sulfur	30	14,101,900	4.03	14,676,000	4.19	22,538,000	6.44
500 MW N 5.0% sulfur	30	16,032,200	4.58	17,741,900	5.07	27,513,400	7.86
1,000 MW E 3.5% sulfur	25	23,241,200	3.32	25,750,900	3.68	36,933,500	5.28
1,000 MW N 3.5% sulfur	30	21,874,300	3.12	24,147,700	3.45	35,602,400	5.09
Solids disposal by trucking							
500 MW N 3.5% sulfur	30	15,172,400	4.33	14,293,900	4.08	-	-
90% SO_2 removal; onsite solids disposal (ponding)							
500 MW N 3.5% sulfur	30	14,651,300	4.19	15,438,800	4.41	23,812,400	6.80
Oil-Fired Power Unit							
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)							
500 MW E 2.5% sulfur	25	11,446,600	3.27	11,128,400	3.18	16,091,700	4.60

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a. Power unit on-stream time, 7,000 hr/yr. Midwest plant location, 1980 revenue requirements. Investment and revenue requirement for removal and disposal of fly ash excluded.

b. These revenue requirements are based on the defined premises and assumptions and the capital investments shown in Table S-1. They would vary as project scope changed; for example, with additions to the scope outlined in Table S-4, annual revenue requirements for limestone could increase to 9.37 mills/kWh for a new, 500-MW unit burning 3.5% sulfur.

TABLE S-3. SUMMARY OF LEVELIZED OPERATING COST OF FGD OVER POWER UNIT LIFETIME (INCLUDING BYPRODUCT CREDIT)[a]

Case	Years remaining life	Limestone process		Generic double-alkali process		Citrate process	
		Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost, mills/kWh[c]	Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost, mills/kWh[c]	Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit operating cost, mills/kWh[c]
Coal-Fired Power Unit							
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)							
200 MW E 3.5% sulfur	20	52,811,700	9.28	53,388,600	9.39	84,862,500	14.92
200 MW N 3.5% sulfur	30	65,253,700	6.56	65,224,800	6.56	104,508,300	10.51
500 MW E 3.5% sulfur	25	122,034,600	5.82	127,562,500	6.09	187,099,800	8.93
500 MW N 2.0% sulfur	30	104,931,000	4.22	103,925,200	4.18	153,984,800	6.20
500 MW N 3.5% sulfur	30	127,709,200	5.14	132,472,900	5.33	200,363,000	8.06
500 MW N 5.0% sulfur	30	144,837,500	5.83	158,278,400	6.37	241,941,500	9.74
1,000 MW E 3.5% sulfur	25	188,891,100	4.51	209,774,100	5.00	293,113,800	6.99
1,000 MW N 3.5% sulfur	30	195,672,000	3.94	215,525,300	4.34	31[illegible],517,300	6.29
Solids disposal by trucking							
500 MW N 3.5% sulfur	30	132,750,600	5.34	125,275,900	5.04	-	-
90% SO_2 removal; onsite solids disposal (ponding)							
500 MW N 3.5% sulfur	30	132,602,400	5.34	138,947,500	5.59	211,103,800	8.50
Oil-Fired Power Unit							
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)							
500 MW E 2.5% sulfur	25	94,271,900	4.50	93,023,600	4.44	131,410,200	6.27

a. Basis
Power unit operating profile for 30-year life = 7,000 hours - 10 years, 5,000 hours - 5 years, 3,500 hours - 5 years, 1,500 hours - 10 years.
Midwest plant location, 1980 operating costs.
Investment and revenue requirements for removal and disposal of fly ash excluded.
Constant labor cost assumed over life of project.

b. Discounted at 10% to initial year.

c. Equivalent to discounted process revenue requirement over life of power unit.

TABLE S-4. LIMESTONE SLURRY PROCESS

ADDITIONAL INVESTMENT REQUIRED FOR MODIFIED PROJECT SCOPE

	Investment required, $/kW
Base case - limestone slurry process: 500-MW new unit burning coal containing 3.5% sulfur, 16% ash, 10,500 Btu/lb heat value; 1.2 lb SO_2 allowable emission per MBtu heat input; 0.1% liquid entrainment in cleaned stack gas; 30-yr life, 127,500-hr operation; no redundancy; 20% contingency; onsite solids disposal; mid-1979 cost basis	97.5
	Additional investment required, $/kW
Modified case: 500-MW new unit burning coal containing 6% sulfur, 16% ash, 10,500 Btu/lb heat value; 90% SO_2 removal; 0.3% liquid entrainment in cleaned stack gas; 30-yr life, 127,500-hr operation; 50% redundancy; on-site solids disposal, mid-1979 cost basis	
Investment increases due to:	
Increased raw material handling	18.3
Larger waste disposal area and pond	46.9
50% redundancy of ball mills, scrubbers, and other equipment	30.8
Total increase in capital investment	96.0

Annual Revenue Requirements

For base case conditions the ranking of average annual revenue requirements for the processes is the same as the investment ranking: (1) limestone slurry, (2) generic double alkali, and (3) citrate.

Capital charges are the largest component of revenue requirements for all processes. Electrical demand is significantly greater for the limestone and citrate processes than for the double-alkali process. Raw materials cost is 19% and 22% of the total revenue requirements for base case citrate and double alkali, respectively, while raw material cost for limestone is only 8% of the total. For all case variations estimated in this study, projected 1980 FGD revenue requirements range from 3.25 to 8.78 mills/kWh.

Lifetime Revenue Requirements

The relative rankings in levelized lifetime revenue requirements are similar to those projected for annual requirements. Lifetime levelized revenue requirements are slightly higher than corresponding average annual revenue requirements because of the declining operating profile of the power unit. The average on-stream time over the life of the plant is 4,250 hr/yr, compared to the higher on-stream time of 7,000 hr/yr used for the annual revenue requirement estimates.

CONCLUSIONS

Because ponding costs for the limestone process offset the additional equipment needs of the double-alkali process, capital investment requirements are quite similar for the two processes. The capital investment for the citrate process is considerably higher; however, it should be recognized that citrate is a recovery process and should also be compared with other recovery processes.

The limestone or lime slurry process is the best known and most completely developed FGD system in the United States today. The evaluation of limestone FGD in this study, reflecting the broad experience of vendors and utilities in constructing and operating this system, is based on considerable available data. Limestone is still the simplest and cheapest FGD process available today for most applications, but it continues to require intensive maintenance effort, and it produces a waste sludge of questionable stability and environmental effect.

Although construction and operating experience is not as extensive for the double-alkali process as for limestone, unit areas in the double-alkali process can be compared either with limestone or with other chemical operations for an understanding of design and operation. Double-alkali FGD is a competitive alternative to limestone, especially when trucking is used to dispose of the waste filter cake. Even though double alkali is a waste-producing process, the system produces less waste solids than limestone, requiring a smaller area for disposal, and it regenerates the process scrubbing liquor. Because of system design, it is expected to require less maintenance than limestone.

As a recovery system, the citrate process is inherently more expensive and should not be compared only with the waste-producing processes evaluated here but also with other recovery processes. For this study the citrate process is assumed proven, but less is known about the unit areas of the process as an integrated operating system than is known about the limestone or double-alkali processes, and the operation of many of these areas is more complex. Although the citrate process offers the advantage of producing a salable byproduct, the use of natural gas in the reduction step could limit its application. It is important that the citrate process be proven in the field in order to more fully answer the questions of real cost and operability.

INTRODUCTION

Coal-fired power plants are a major source of the sulfur dioxide (SO_2) emitted to the atmosphere in the United States. By the end of 1976, 54% of the electricity generated in the United States was being produced from coal-fired power plants according to Electrical World (1977c). The Federal Energy Administration (FEA) predicts that by 1985 this figure will increase to 70% of the total electrical energy produced (Electrical World, 1977b). Critical attention is focused on the electrical power utility industry as it searches for reliable emission control methods that will meet the air quality regulations.

Possible SO_2 control alternatives to flue gas desulfurization (FGD) do exist. However, recent court decisions have denied the use of tall stacks and reduced production during periods of weather stagnation as control methods. Projected shortages of natural gas and fuel oils force a growing dependence on coal, but low-sulfur coal is not found in sufficient quantity in regions of greatest electrical demand. While the concept of coal desulfurization prior to combustion is under study, its development has not yet reached the commercial status of FGD.

Although scattered attempts at power plant SO_2 control were pursued in Europe as early as the 1930's clean air legislation in the United States made SO_2 control a necessity in this country in the 1960's. At this time government-sponsored research and development (R&D) began to focus attention on FGD and it became increasingly important to be able to evaluate the systems technically and economically from a standard basis of comparison. In 1967 the National Center for Air Pollution Control (now part of the U.S. Environmental Protection Agency--EPA) contracted with the Tennessee Valley Authority (TVA) for a series of conceptual design and economic studies to be carried out by TVA on FGD processes. The first studies evaluated four processes.

- Dry process limestone injection (TVA, 1968)
- Limestone wet scrubbing (TVA, 1969)
- Ammonia scrubbing (TVA, 1970)
- Magnesia scrubbing (McGlamery, et al., 1973)

The earliest SO_2 removal systems were limestone or lime processes and much of the R&D through the late 1960's and early 1970's focused on limestone and lime as absorbents. A previous TVA-EPA publication (McGlamery, et al., 1975) included evaluations of limestone slurry and lime slurry scrubbing. Most FGD systems operating today at power unit sites are limestone or lime, representing over 90% of the 13,000 MW of removal capacity (commercial and demonstration) currently employed at U.S. power plants by 1978 (Laseke, et al., 1978).

Although limestone and lime processes are considered the least expensive methods of FGD at this time, the processes have several disadvantages: (1) they require intensive maintenance, (2) they are once-through processes, i.e., the scrubbing slurry is not regenerated for reuse, and (3) the SO_2 is removed in the form of a waste sludge. Continuing R&D has developed processes that minimize or eliminate one or more of these problems.

Two of the three processes selected for evaluation in this study offer possible solutions to the disadvantages mentioned. The generic double-alkali process, representing several of the double-alkali processes now available in the United States, reduces maintenance requirements by introducing lime as a second alkali outside the scrubbing loop, thereby reducing the potential for calcium scaling. Although the system produces a waste sludge that is principally calcium sulfite, it does regenerate the sodium scrubbing liquor for recycle. The citrate process, based on the U.S. Bureau of Mines FGD system, also regenerates and recycles its scrubbing liquor. In addition, the process reduces the removed SO_2 to elemental sulfur, an important chemical feedstock.

TVA-EPA studies now in preparation will evaluate processes producing salable sulfur compounds on a comparative basis.

PROCESS BACKGROUND AND DESCRIPTION

Full-scale scrubbing of power plant flue gas was first undertaken at the Battersea power station in London, England, in the early 1930's. This and the scrubbing systems at English power stations that followed in the decade of the 1930's posed many chemical and design questions. Investigators such as G. W. Hewson, et al. (1933), J. L. Pearson, et al. (1935), and R. L. Rees (1953) in England and H. F. Johnstone, et al. (1938) in the United States studied these and other factors pertaining to SO_2; much of their research is still applicable today and forms the basis for current R&D. The most concentrated R&D effort in the United States toward improved FGD has occurred in the past 15 years, especially since the passage of the clean air legislation in 1967 and 1970. A useful summary of regulations proposed through mid-1976 has been prepared by Chaput (1976).

For a better understanding of the specific processes evaluated in this study, the development of each is given including present status, process characteristics, and chemistry.

LIMESTONE SLURRY PROCESS

Limestone and lime absorption systems are the most widely used technology in the United States today for SO_2 removal from fossil-fueled power plant flue gas. About 90% of the equivalent megawatts for which removal systems are in use, under construction, or planned is limestone or lime absorption (Kennedy and Tomlinson, 1978).

The chemistry of limestone slurry scrubbing can be described by the following series of reactions from McGlamery, et al. (1975). Equations 1, 2, and 3 are reactions of SO_2 absorption in an aqueous scrubbing liquor.

$$SO_{2(g)} \rightleftarrows SO_{2(aq)} \tag{1}$$

$$SO_{2(aq)} + H_2O \rightleftarrows H_2SO_3 \rightleftarrows HSO_3^- + H^+ \tag{2}$$

$$HSO_3^- \rightleftarrows H^+ + SO_3^= \tag{3}$$

Simultaneously, limestone dissolves into the scrubbing liquor as shown in equations 4 and 5.

$$CaCO_{3(s)} \rightleftarrows CaCO_{3(aq)} \tag{4}$$

$$CaCO_{3(aq)} \rightleftarrows Ca^{++} + CO_3^= \tag{5}$$

Sulfite ion combines with calcium to yield the very insoluble calcium sulfite hemihydrate.

$$Ca^{++} + SO_3^{=} + 1/2H_2O \rightleftarrows CaSO_3 \cdot 1/2H_2O\downarrow \tag{6}$$

Carbon dioxide, either in the flue gas or from calcium carbonate interacts with water as shown in equations 7 and 8.

$$CO_{2(g)} + H_2O \rightleftarrows H_2CO_{3(aq)} \rightleftarrows H^{+} + HCO_3^{-} \tag{7}$$

$$HCO_3^{-} \rightleftarrows H^{+} + CO_3^{=} \tag{8}$$

In addition, sulfite ion may be ultimately converted to gypsum by the following reactions.

$$SO_3^{=} + 1/2O_2 \rightarrow SO_4^{=} \tag{9}$$

$$Ca^{++} + SO_4^{=} + 2H_2O \rightleftarrows CaSO_4 \cdot 2H_2O_{(s)}\downarrow \tag{10}$$

Because detailed discussions of process development may be found in many publications by TVA (TVA, 1970; McGlamery, et al., 1975; Kennedy and Tomlinson, 1978), only a brief historical description of the limestone slurry process and some codevelopment of lime slurry will be included here.

The scrubbing process developed by the London Power Company for its Battersea and Bankside power stations (Hewson, et al., 1933; Rees, 1953) used alkaline water from the Thames River to remove dust and SO_2 from boiler exhaust gases. The once-through system returned acidic effluent to the Thames and required very large quantities of water which cooled the gas to low temperatures creating plume problems. To overcome these difficulties, Howden and Company and Imperial Chemical Industries (Howden - ICI) developed a lime-scrubbing process which was a first attempt at closed-water-loop operation. A process pilot plant was constructed in Billingham in 1933 and the process was used commercially at the Tir John (Swansea) and Fulham (London) power stations. The Tir John scrubbing system was soon shut down because of operational difficulties from the high ash content of the coal. Fulham operated until World War II. The two Battersea scrubbers were closed permanently in 1969 and 1974 because of plume problems and Bankside is now England's only operational FGD system.

Although Canada and the USSR began SO_2 removal development in the 1930's and 1940's using sorbents other than limestone or lime, very little more was done with limestone and lime scrubbing during this time. In 1953 TVA began a brief series of pilot-plant studies of several FGD processes including a packed-tower scrubber using a 10% slurry of pulverized limestone (Slack, 1971). Reliance on atmospheric monitoring and tall stack dispersion during this period reduced TVA's interest in the expansion of these studies.

FGD development intensified in the 1960's. Wisconsin Electric Power and Universal Oil Products conducted a 1-MW joint program in 1965 (Pollack, et al., 1967) on a coal-fired 120-MW boiler. Combustion Engineering and Detroit Edison (Plumley, et al., 1967) collaborated on a 1966-1967 program to study limestone injection into a boiler. Other U.S. companies--Babcock and Wilcox Company, Chemical Construction Corporation (Chemico), Research-Cottrell, Inc., Zurn Industries, and Peabody Coal Company--also developed limestone scrubbing data during this decade.

A joint TVA-EPA-Bechtel program began in 1967 at TVA's Shawnee Steam Plant, Paducah, Kentucky (Bechtel Corporation, 1973). The EPA-funded test demonstration facility includes three 10-MW scrubbers of different types; the test program is directed by Bechtel and the facility is operated by TVA. All phases of limestone and lime scrubbing are being studied, from operating optimization to equipment reliability. At present two of the scrubbers, a venturi followed by a spray tower and a Turbulent Contact Absorber (TM) (TCA), are being operated in an advanced test program which began in June 1974 and is scheduled to run through December 1979 (Head, 1977; Head, et al., 1978). The program objectives include demonstrating process and equipment reliability under varying flue gas conditions, determining the effect of additives on SO_2 removal, determining the effectiveness of forced oxidation to produce an improved waste sludge product, characterizing stack gas emissions, and evaluating methods of automatic control. In August 1978 a program sponsored by the Electric Power Research Institute (EPRI) was begun to study cocurrent limestone scrubbing on the third scrubber.

In conjunction with the EPA-sponsored Shawnee test program, Bechtel and TVA have jointly developed a computer program capable of projecting comparative investment and revenue requirements for limestone and lime scrubbing (Torstrick, et al., 1978). The computer program has been developed to permit the estimation of relative economics of limestone and lime scrubbing systems for variations in process design alternatives or variations in the values of independent design variables. Although the program is not intended to compute the economics of an individual system to a high degree of accuracy, it is based on sufficient detail to allow the rapid projection of preliminary conceptual design and costs for various limestone and lime case variations on a common design and cost basis.

Currently, 11 commercial-sized limestone units are in operation in the United States (Table 1). Kansas Power and Light Company's Lawrence installation was the initial system cited by EPA as evidence of demonstrated technology. The limestone injection - wet scrubber system has been replaced on unit 4 with limestone scrubbing in a spray tower. The new system went onstream in January 1977. The same type scrubber changes were made on unit 5 and this operation began in mid-1978. The boilers began burning Wyoming low-sulfur coal (0.5%) in the fall of 1974.

TABLE 1. COMMERCIAL, OPERATIONAL LIMESTONE FGD

SYSTEMS AT U.S. ELECTRIC POWER STATIONS (DECEMBER 1977)

Power plant			FGD installation			
Utility	Station	Unit No.	FGD MW	startup	New/ retrofit	Vendor
Kansas Power and Light	Lawrence	4	125	12/68 1/77	R	Combustion Engineering
Kansas Power and Light	Lawrence	5	400	11/71 6/78	N	Combustion Engineering
Kansas City Power and Light	La Cygne	1	820	2/73	N	Babcock and Wilcox
Arizona Public Service	Cholla	1	115	10/73	R	Research-Cottrell
Northern States Power	Sherburne	1	710	3/76	N	Combustion Engineering
Northern States Power	Sherburne	2	680	4/77	N	Combustion Engineering
Springfield City Utilities	Southwest	1	200	4/77	N	Universal Oil Products
Tennessee Valley Authority	Widows Creek	8	550	5/77	R	Tennessee Valley Authority
South Carolina Public Service	Winyah	2	140	7/77	N	Babcock and Wilcox
Texas Utilities Company	Martin Lake	1	793	8/77	N	Research-Cottrell
Indianapolis Power and Light Company	Petersburg	3	530	12/77	N	Universal Oil Products

La Cygne unit 1 (Kansas City Power and Light) has eight identical venturi-sieve tray modules for fly ash and SO_2 removal. The unit burns high-ash (15% to 25%), high-sulfur (5.3% to 6%) coal which is mined locally. An intensive development program has been conducted at the site; however, operating and maintenance problems remain.

Flooded disc scrubbers and packed-tower absorbers were retrofitted to the 115-MW boiler of Arizona Public Service's Cholla unit 1. The unit burns 0.5% sulfur coal. High on-stream time has been achieved, but extensive maintenance and operation efforts are required.

Sherburne station boilers Nos. 1 and 2 burn low-sulfur (0.8%) coal. Each unit has 12 scrubbing modules. Each module operates with a ventri-rod scrubber followed by a marble-bed absorber. Erosion and spray nozzle plugging have caused problems in these units. Northern States Power Company is planning two additional power units of 860 MW each at Sherburne with limestone slurry FGD included for each unit.

During startup, the FGD system at Southwest No. 1 (Springfield City Utilities) experienced mist eliminator scaling and some control problems. It is anticipated that scrubber system modifications will be made during a scheduled outage. The unit burns 3.5% sulfur coal.

Coal with 3.7% sulfur content is burned in TVA's Widows Creek Unit 8. The TVA-designed scrubbing system has four trains, each of which includes a variable-throat venturi followed by a grid-type absorber. Commercial scrubber operation began in late 1977.

The scrubbing unit on Winyah No. 2, a part of the South Carolina Public Service system, began initial operation in July 1977. Fuel for the unit is a 1% sulfur Virginia coal. Plans are underway to increase the size of the scrubber which now cleans 50% of the flue gas from Unit 2.

Texas lignite with 1% sulfur and 8% ash content is burned in the new Martin Lake Unit 1 boiler of Texas Utilities Company. Six packed/spray tower absorbers scrub 75% of the total flue gas with the remainder bypassed for reheat. Compliance testing began in late 1977.

Indianapolis Power and Light Company has installed TCA limestone scrubbers at their new Petersburg No. 3 unit. The unit burns 3.5% sulfur with ash content of 10%. Operation of the four modules began in December 1977.

In addition to the 11 operating limestone units listed, another 17,500 equivalent megawatts of limestone FGD units are under construction or planned (Laseke, et al., 1978; Kennedy and Tomlinson, 1978).

The process design data and operating conditions used in this study for the limestone slurry process are based primarily on the latest design and operating conditions at the TVA Shawnee test facilities and Widows Creek Unit 8.

GENERIC DOUBLE-ALKALI PROCESS

As in the limestone slurry system, double-alkali processes dispose of removed SO_2 as throwaway calcium sludge. Unlike limestone, however, absorption of SO_2 and production of disposable waste are separated--the addition of limestone or lime occurring outside the scrubber loop. The scrubbing step utilizes an aqueous solution of soluble alkali. The absorption reaction depends on gas/liquid chemical equilibrium and mass transfer rates of sulfur oxides (SO_x) from flue gas to scrubbing liquid instead of limestone dissolution, the limiting factor in limestone scrubbing. Therefore, SO_x absorption efficiency in a double-alkali system is potentially higher than in a limestone system with the same physical dimensions and liquid-to-gas (L/G) flow rates (Kaplan, 1974). Scaling and plugging in the absorption area are reduced because calcium slurry is confined to the regeneration and disposal loop and soluble calcium is minimized in the scrubber liquor. The process has been described by Kaplan (1976) and LaMantia, et al. (1976, 1977).

Technically, the use of any combination of alkaline compounds, organic or inorganic, for SO_2 removal and disposal can be classified as a double-alkali process. The process chosen for evaluation in this report is a sodium sulfite absorbent - lime reactant system.

Sodium sulfite in solution absorbs SO_2 in the scrubbing step represented by equation 11.

$$SO_3^{=} + SO_2 + H_2O \rightarrow HSO_3^{-} \qquad (11)$$

Sodium hydroxide formed in the regeneration step and sodium carbonate added as sodium makeup react with SO_2 as shown below. The absorption reactions actually involve reaction of SO_2 with an aqueous base such as sulfite, hydroxide, or carbonate rather than sodium ion which is present only to maintain electrical neutrality.

$$2OH^{-} + SO_2 \rightarrow SO_3^{=} + H_2O \qquad (12)$$

$$CO_3^{=} + SO_2 \rightarrow SO_3^{=} + CO_2 \qquad (13)$$

The use of lime for regeneration allows the system to be operated over a wider pH range which in turn includes the complete range of active alkali-hydroxide/sulfite/bisulfite. Limestone regeneration operates only in the sulfite/bisulfite range.

$$Ca(OH)_2 + 2HSO_3^{-} \rightarrow SO_3^{=} + CaSO_3 \cdot 1/2H_2O + 3/2H_2O \qquad (14)$$

$$Ca(OH)_2 + SO_3^{=} + 1/2H_2O \rightarrow 2OH^{-} + CaSO_3 \cdot 1/2H_2O \qquad (15)$$

$$Ca(OH)_2 + SO_4^{=} \rightleftarrows 2OH^{-} + CaSO_4 \qquad (16)$$

$$Ca(OH)_2 + SO_4^{=} + 2H_2O \rightleftarrows 2OH^{-} + CaSO_4 \cdot 2H_2O \qquad (17)$$

Total oxidizable sulfur (TOS) is the total concentration of sulfite and bisulfite in solution. Oxidation of TOS to sulfate may occur in any part of the system and is affected by composition of the scrubbing liquor, oxygen content of the flue gas, impurities in the lime, and design of the equipment.

$$SO_3^{=} + 1/2O_2 \rightarrow SO_4^{=} \quad (18)$$

$$HSO_3^{-} + 1/2O_2 \rightarrow SO_4^{=} + H^{+} \quad (19)$$

The sum of the concentrations of NaOH, Na_2CO_3, $NaHCO_3$, Na_2SO_3, and $NaHSO_3$ in the scrubbing solution is termed active alkali. The active alkali concentration in a system can be dilute or concentrated; a concentrated mode (active sodium concentration greater than 0.15 M) was chosen for this study. In this mode high sulfite levels prevent the precipitation of calcium sulfate ($CaSO_4$) as gypsum ($CaSO_4 \cdot 2H_2O$), equation 17. However, $CaSO_4$ is precipitated along with calcium sulfite ($CaSO_3 \cdot 1/2H_2O$) as shown in equations 14-16. In this way the system can keep up with sulfite oxidation at the rate of 25% to 30% of the SO_2 absorbed without becoming saturated with $CaSO_4$. Usually, soluble calcium levels are less than 100 ppm in the regenerated liquor of a concentrated mode double-alkali process.

Several U.S. and Japanese companies have developed double-alkali FGD processes. Unlike the Japanese processes which generally result in the production of gypsum, U.S. processes are of the waste-producing type, producing a calcium sludge that is primarily $CaSO_3 \cdot 1/2H_2O$.

The first U.S. patent for a double-alkali system was awarded to FMC Corporation in October 1975. FGD investigation was started at FMC in 1956 with limestone and lime scrubbing (FMC, 1976; Legatski, 1976), but by the 1960's FMC was testing a sodium-based scrubbing process on a pilot-plant scale.

The process produce sodium sulfite (Na_2SO_3) and sodium sulfate (Na_2SO_4) and when efforts to sell these products failed, FMC began a search to find a method of recovering the sodium values from the system while producing an acceptable solid waste for disposal. The resulting concentrated double-alkali process was demonstrated as an equivalent 30-MW prototype installed on a reduction kiln at FMC's Modesto (California) Chemical Plant in 1971. Since 1971 several installations have been constructed or are planned for industrial boilers of up to 150 MW equivalent size. Removal of SO_2 and unit availability have been 90% or greater. An FMC system, scrubbing flue gas from coal of 3.75% sulfur, is planned for the 250-MW A. B. Brown Unit No. 1, Southern Indiana Gas and Electric Company (Table 2).

TABLE 2. COMMERCIAL, DOUBLE-ALKALI FGD

SYSTEMS UNDER CONSTRUCTION AT U.S.

ELECTRIC POWER STATIONS

Power plant			FGD installation			
Utility	Station	Unit No.	FGD MW	FGD startup	New/ retrofit	Vendor
Louisville Gas and Electric	Cane Run	6	277	2/79	R	Combustion Equipment Associates/Arthur D. Little
Southern Indiana Gas and Electric	A. B. Brown	1	250	4/79	N	FMC Corporation
Central Illinois Public Service	Newton	1	575	11/79	N	Buell/Envirotech

Envirotech Corporation developed its Buell double-alkali SO_2 control process for both dilute and concentrated mode operation (Bloss, et al., 1976). A joint R&D effort with Utah Power and Light Company was undertaken at Gadsby station in Salt Lake City. The 1-MW pilot plant began testing in January 1972. Envirotech research has also focused on high-chloride coals and the acceptable disposal of chlorides in a throwaway system. At present Envirotech is constructing a 575-MW FGD system at Newton station unit 1, Central Illinois Public Service (Table 2). Unit 1 will burn coal containing 4% sulfur and 0.2% chloride.

In 1972 Arthur D. Little, Inc., (ADL) was awarded a $1.1M EPA contract to develop double-alkali technology. In the ADL laboratory program, tests were conducted to develop process chemistry, to study regeneration of sodium scrubbing solutions, and to characterize double-alkali waste products (LaMantia, et al., 1976, 1977). ADL, in conjunction with Combustion Equipment Associates, Inc., (CEA), conducted pilot-plant work involving both concentrated and dilute modes of operation. A 20-MW prototype double-alkali system using lime in a concentrated mode was designed and developed by CEA and ADL for installation at Gulf Power Company's Scholz Steam Plant at Sneads, Florida. The test program, a part of the EPA contract, ran from May 1975 to July 1976. CEA and ADL have been awarded an EPA contract for a full-scale double-alkali demonstration unit now under construction at Cane Run Unit 6, Louisville Gas and Electric Company (Van Ness, 1978). Coal sulfur content at Unit 6 is 3.5% to 4%. Although the entire cost of the installation, $16.3M, is being borne by Louisville Gas and Electric, EPA will provide additional funding of $4.5M to cover performance testing and a 1-year operational study. SO_2 removal efficiencies greater than 95% have been guaranteed (Table 2).

Other U.S. companies have developed double-alkali processes or have conducted experimental programs to study process feasibility. A dilute mode, limestone regeneration double-alkali system, developed by General Motors Corporation and installed at its Parma, Ohio, steam plant, was put into operation March 1974 (Interess, 1977). Under contract to EPA, ADL conducted a 2-year test program at the Parma site to study operating characteristics and waste byproduct properties of the system. The Zurn double-alkali process (Zurn Industries, Inc.) is in use at the Caterpillar Tractor Company plant in Joliet, Illinois (Lewis, 1976). The process is dilute mode, lime regeneration, and scrubs gas from two industrial boilers burning 4% sulfur coal. The CALSOX system, a Monsanto Enviro-Chem Systems, Inc., development (Barnard, et al., 1974), absorbs SO_2 in an aqueous solution of ethanolamine and regenerates scrubbing liquor with lime. Chemico and Bechtel have also conducted pilot-plant tests of double-alkali systems.

Double-alkali process chemistry was studied in the laboratories of EPA at Research Triangle Park, North Carolina (Draemel, 1972), in the early 1970's as a part of an EPA program which included work contracted to Radian Corporation and ADL. Radian designed a mathematical model of the double-alkali system which included certain chemical species not already considered in the laboratory. A bench-scale study was undertaken by ADL to find optimum equipment arrangement, to develop mass transfer coefficients, and to use process knowledge to develop economic information about the system.

Also in the early 1970's laboratory- and bench-scale studies of sodium and ammonia sorbents were conducted by TVA (TVA, 1973, 1974) using limestone or lime as regenerants. A pilot-plant study at TVA's Colbert Steam Plant was developed under EPA contract using an ammonia system; the study concluded in 1976 (Williamson and Puschaver, 1977).

The design of the generic double-alkali process evaluated in this study follows the development of U.S. double-alkali throwaway systems, using a concentrated mode with sodium sulfite absorbent and lime regenerant.

CITRATE PROCESS

The U.S. Bureau of Mines Metallurgy Research Center at Salt Lake City began FGD research in 1968 to find ways to control SO_2 emissions from the nonferrous smelting industry. After a year of testing many possible organic and inorganic sorbing combinations, an aqueous solution of sodium citrate and citric acid was chosen for its chemical stability, low vapor pressure, high SO_2 absorption, completeness of regeneration, and purity of the resulting sulfur (Rosenbaum, et al., 1971; McKinney, et al., 1974a). The chemistry of the citrate process was investigated in laboratory studies by the Bureau of Mines and by Pfizer, Inc. (Korosy, 1974). In the absorption stage SO_2 dissolves in water, but the absorption is self limiting.

$$SO_2 + H_2O \rightleftarrows HSO_3^- + H^+ \qquad (20)$$

Hydrogen ions are removed and solubility increases by the buffering action of the various citrate species.

$$Cit^{\equiv} + H^+ \rightleftarrows HCit^{=} \qquad (21)$$

$$HCit^{=} + H^+ \rightleftarrows H_2Cit^- \qquad (22)$$

$$H_2Cit^- + H^+ \rightleftarrows H_3Cit \qquad (23)$$

Some thiosulfate, formed in the regeneration step, will recycle with the absorbing solution and can form a complex with SO_2.

$$H^+ + HSO_3^- + S_2O_3^{=} \rightleftarrows SO_2 \cdot S_2O_3^{=} + H_2O \qquad (24)$$

Reaction between bisulfite and thiosulfate can result in the formation of trithionate.

$$4HSO_3^- + S_2O_3^{=} + 2H^+ \rightarrow 2S_3O_6^{=} + 3H_2O \qquad (25)$$

Although the complexing of absorbed SO_2 (equation 24) inhibits oxidation to sulfate, some oxidation will occur during absorption.

$$HSO_3^- + 1/2O_2 \rightarrow HSO_4^- \rightleftarrows H^+ + SO_4^{=} \qquad (26)$$

The reaction of hydrogen sulfite (H_2S) and SO_2 in aqueous solution during regeneration is complex and thiosulfate and other intermediates are formed. Reduction of these and the intermediates of equations 24 and 25 result in the following general equations.

$$SO_3^= + 2H_2S + 2H^+ \rightarrow 3S + 3H_2O \tag{27}$$

$$S_2O_3^= + 2H_2S + 2H^+ \rightarrow 4S + 3H_2O \tag{28}$$

Some decomposition of thiosulfate occurs during the sulfur-melting step at temperatures above 257°F (125°C). The overall reaction is

$$3S_2O_3^= + 2H^+ \rightarrow 2SO_4^= + 4S + H_2O \tag{29}$$

Sulfate formed by equations 26 and 29 is purged from the system by the addition of alkali to neutralize the hydrogen ions which have also formed.

$$H^+ + SO_4^= + Na_2CO_3 \rightarrow 2Na^+ + SO_4^= + H_2O + CO_2 \tag{30}$$

Natural gas and steam are reacted with a portion of the product sulfur to produce H_2S for the regeneration step (equations 26 and 27).

$$CH_4 + 4S + 2H_2O \rightarrow 4H_2S + CO_2 \tag{31}$$

The initial Bureau of Mines process was designed to include the following steps: (1) gas cooling and cleaning, (2) SO_2 absorption in citrate solution, (3) reaction of absorbed SO_2 with H_2S, (4) washing of precipitated sulfur, and (5) formation of H_2S. Laboratory-scale tests in 1970 processed up to 15 ft^3/min of gas containing 0.3% to 2.0% SO_2. In these tests the precipitated sulfur was not washed but was filtered and melted to separate the occluded citrate. H_2S preparation was not a part of these tests.

In November 1970, a pilot plant treating a maximum 400 ft^3/min of reverberatory furnace gas was placed into operation jointly by the Bureau of Mines and Magma Copper Company, a subsidiary of Newmont Mining Corporation, at the San Manuel smelter in Arizona (McKinney, et al., 1974b; Rosenbaum, et al., 1973). Liquid H_2S was purchased for the SO_2 reduction process step. The operation of the pilot plant was frequently interrupted by mechanical failures; however, the Bureau of Mines concluded that (1) the process could remove 90% to 99% of the SO_2 from the smelter gas, (2) regeneration of the scrubbing liquor was easily managed, and (3) high-quality sulfur could be recovered by a combination of thickening, centrifuging, and melting.

In 1971 Pfizer, Inc., a chemical plant operator and manufacturer of citric acid, working with the Bureau of Mines built and operated laboratory units to study citrate process chemistry. Arthur G. McKee and Company and Peabody Engineered Systems joined Pfizer in 1972 in plans to demonstrate the commercial feasibility of the citrate process (Korosy, 1974). A 2,000 sft^3/min pilot plant was constructed at Pfizer's Vigo plant site in Terre Haute, Indiana. The gas stream, from a coal-fired industrial boiler, averaged 1,000 ppm SO_2 at the inlet to the FGD system. Two major design changes incorporated in this pilot plant were the impingement plate tower which replaced the packed tower of the Bureau of Mines system and sulfur separation which was accomplished by air rather than hydrocarbon flotation. Peabody at one time offered this system under the trade name Citrex process.

Further investigation by the Bureau of Mines continued in February 1974 at the Bunker Hill Company lead smelter, Kellogg, Idaho. A pilot plant, using a packed tower with polypropylene Intalox saddles and sized to treat 1,000 sft^3/min of 0.5% SO_2 gas, was designed to be operated in three phases (McKinney, et al., 1974). In Phase I, a smeltering furnace gas containing 4% to 5% SO_2 was diluted with air to 0.5% SO_2. Purchased liquid H_2S was used for reducing the SO_2 to sulfur. Phase II operation was similar to Phase I with the exception that a 76% to 78% H_2S gas produced onsite from product sulfur, natural gas, and steam was used as the reducing gas. In Phase III tail gas from the lead smelter sinter plant, containing 0.3% to 0.9% SO_2, was used as feed. A gas cooling and cleaning plant was designed to recover the dust in the tail gas in a baghouse, cool the gas in a packed wet scrubber, and remove sulfuric acid (H_2SO_4) mist and trace particles in a wet electrostatic precipitator (ESP). The Bunker Hill citrate pilot plant operated through November 1975 for a total of 4,500 hours and produced about 50 net tons of high-quality sulfur.

With EPA, the Bureau of Mines initiated plans for a full-scale citrate process demonstration plant and in mid-1976 entered into a cost-sharing cooperative agreement with the St. Joe Minerals Corporation to provide the host site (Madenburg and Kurey, 1978). A citrate process demonstration plant has been constructed at St. Joe's 60-MW coal-burning G. F. Weaton electric generating station at Monaca, Pennsylvania. Morrison-Knudsen Company of Boise, Idaho, has built the plant under a turnkey design/build/operate contract. The retrofitted system will treat 156,000 sft^3/min of flue gas and is scheduled to begin operation in the summer of 1979. At that time Radian will begin a 1-year emission testing and performance evaluation of the demonstration system.

The citrate process design data and operating criteria used in this study are based primarily on the Bureau of Mines process. Design differences in the citrate process demonstration plant at Weaton Station are cited in the Systems Estimated, Citrate Process section below.

DESIGN AND ECONOMIC PREMISES

To make the comparison of process evaluations as equitable as possible, it is essential to carefully define the design and economic premises used as a basis for the study calculations. TVA has been involved in establishing study criteria and preparing technical and economic evaluations of alternate FGD processes for EPA and others since 1967. A report published by TVA and EPA (McGlamery, et al., 1975) outlined in detail a set of premises developed by TVA for use in its evaluation studies. Recently these premises have been modified through discussions with EPA and others to reflect prevailing fuel characteristics, current design practice, and projected economic conditions.

DESIGN PREMISES

The updated values used in this study are considered to be representative of modern boiler units less than 10 years old for which FGD would be considered. The base case is a new 500-MW power unit with a heat rate of 9,000 Btu/kWh, burning 3.5% sulfur coal (dry basis). Criteria that establish efficiencies, production rates, and other process design characteristics that are common to FGD systems are also included.

Power Plant

Both coal- and oil-fired power units are considered in the power plant design premises; because of decreasing emphasis on oil as a fuel source of electricity, however, only one oil-fired case--an existing 500-MW unit--is evaluated. A midwestern location (Illinois, Indiana, Kentucky area) is assumed for the power units because of the concentration of power stations in that area and their proximity to major coal fields.

Fuels--

Although coals of low sulfur and ash contents and high heating values are the most desirable, availability, location, and price often result in the use of coals of lesser quality. To represent the wide range of coals currently being burned, sulfur contents of 2.0%, 3.5%, and 5.0% (dry basis) were chosen. The coal composition was altered from previous studies to reflect a lower heating value (HHV) of 10,500 Btu/lb (as fired) and a higher ash content of 16%. The as-fired coal composition and flow rate for the three sulfur levels are given in Table 3.

A No. 6 fuel oil with 2.5% sulfur and an ash content of 0.1% is assumed for the oil case variation (Table 4). A heating value of 144,000 Btu/gal is assumed.

TABLE 3. COAL COMPOSITIONS AND FLOW RATES AT VARYING SULFUR LEVELS

(500-MW new unit, 9,000 Btu/kWh heat rate,
10,500 Btu/lb higher heating value of coal)

Coal components	Base case 3.5% S (dry basis)		2.0% S (dry basis)		5.0% S (dry basis)	
	Wt %, as fired	Lb/hr, as fired	Wt %, as fired	Lb/hr, as fired	Wt %, as fired	Lb/hr, as fired
C	57.56	246,800	58.03	248,700	56.89	244,000
H	4.14	17,700	4.17	17,900	4.09	17,500
N	1.29	5,500	1.30	5,600	1.27	5,400
O	7.00	30,000	7.81	33,500	6.40	27,400
S	3.12	13,400	1.80	7,700	4.46	19,100
Cl	0.15	600	0.15	600	0.15	600
Ash	16.00	68,600	16.00	68,600	16.00	68,600
H_2O	10.74	46,000	10.74	46,000	10.74	46,000
Total	100.00	428,600	100.00	428,600	100.00	428,600

TABLE 4. FUEL ALTERNATIVE CASE

OIL COMPOSITION AND FLOW RATE

(500-MW existing unit, 9,200 Btu/kWh heat rate, 2.5% S)

Oil components	Wt %, as fired	Lb/hr
C	83.66	204,100
H	11.46	28,000
N	0.63	1,500
O	1.25	3,000
S	2.50	6,100
Ash	0.10	200
Sediment	0.40	1,000
Total	100.00	243,900

Design--

The size of operating fossil-fueled power plants in the United States today ranges to 1300 MW. Of the new units scheduled for commercial service in 1977 through 1980, sizes for coal-fired boilers range from 80-1300 MW (Electrical World, 1977a). Although a considerable portion of the future generating capacity will be from power units 500 MW or larger, many older and smaller units, 200 MW or less, will continue operation in the years to come. Therefore, to determine the effect of power unit size on the economics of SO_2 removal, three unit sizes--200, 500, and 1,000 MW--are chosen for study.

Balanced-draft boiler design is assumed for a horizontal, pulverized coal, frontal-fired unit. A tangential-fired boiler is assumed for the oil-fired unit. ESP units designed to remove 99.5% of the particulate matter are assumed to be located ahead of the FGD system for coal-burning units. Fly ash emission from oil-fired units does not exceed the EPA particulate emission standard; therefore, these power plants do not require fly ash collection facilities.

A balanced-draft power unit without an SO_2 removal unit normally requires one induced-draft (ID) fan per duct, capable of overcoming a pressure drop of approximately 15 inches downstream of the boiler. In the design of new power plants with SO_2 removal facilities, it is assumed that the balanced-draft system includes the same capacity ID fan which will feed flue gas into a common plenum. Downstream from the plenum one forced-draft (FD) fan (relative to the SO_2 absorber) is provided per scrubbing train to overcome the additional pressure drop attributed to SO_2 removal. Since existing power units are already equipped with a 15-inch ID fan, retrofitted SO_2 removal facilities will follow the same design by adding one FD fan per scrubbing train downstream of the plenum.

In this evaluation 200-MW power units are assumed to have two economizers, air heaters, and exhaust ducts, while 500- and 1,000-MW units are assumed to be equipped with four of each.

Operation--

Based on power plant evaluation guidelines suggested by the Federal Energy Regulatory Commission (FERC) (formerly the Federal Power Commission) (FERC, 1968), the expected operating life of a new fossil-fueled power unit is about 30 years. Reflecting past TVA experience (Slack, et al., 1971), Table 5 shows the power plant operating schedule assumed for this study. This schedule represents a total on-stream time of 127,500 hours over the life of the plant. Existing 200-MW units are assumed to be 10 years old with a remaining life of 20 years or 57,500 operating hours; existing 500- and 1,000-MW units are assumed to be 5 years old with a remaining life of 25 years or 92,500 operating hours.

TABLE 5. ASSUMED POWER PLANT CAPACITY SCHEDULE

Operating year	Capacity factor, %	Annual operating time, hr
1-10	80	7,000
11-15	57	5,000
16-20	40	3,500
21-30	17	1,500
Average for 30-yr life	48.5	4,250

Power plant efficiencies vary with size and status. FERC data (1973) list heat rates for approximate 500-MW power units up to 5 years old, ranging from 8,800 to 12,800 Btu/kWh. Representative heat rates chosen for use in this study are given in Table 6.

TABLE 6. POWER UNIT INPUT HEAT REQUIREMENTS

Size, MW	Status	Heat rate, Btu/kWh
1,000	New	8,700
1,000	Existing	9,000
500	New	9,000
500	Existing	9,200
200	New	9,200
200	Existing	9,500

Flue gas compositions vary with power unit design, fuel, and a variety of operating conditions. The following combustion and emission parameters for determining gas composition are based on FERC (1976) and EPA (1973) data for balanced-draft boiler design and average values for the sulfur content of coal. Not taken into consideration are variations in coal--sulfur in actual coal deliveries--which can result in levels as much as 22% greater than average values.

Coal-fired units--Flue gas compositions are based on combustion of pulverized coal and a total air rate to the air preheater equivalent to 133% of stoichiometric requirement. This includes 20% excess air to the boiler and 13% air inleakage at the air preheater. These values reflect operating experience with typical horizontal, frontal-fired, coal-burning units. It is assumed that 80% of the ash present in coal is emitted as fly ash and 95% of the sulfur in coal is emitted as SO_x. One percent of the SO_x emitted is assumed to be sulfur trioxide (SO_3), the remainder is SO_2. Nitrogen oxides (NO_x) emission is reported as nitric oxide (NO).

Oil-fired unit--A tangential-fired boiler is considered for the oil-fired units with flue gas composition estimated assuming a total air rate to the air preheater equivalent to 115% of the stoichiometric requirement. This includes 5% excess air to the boiler with an estimated 10% air inleakage at the preheater. It is also assumed that all of the ash and sulfur in the fuel oil is emitted as fly ash and SO_x. One percent of the SO_x emitted is assumed to be SO_3.

The flue gas compositions and flow rates calculated from these parameters are shown in Table 7. Calculated flue gas and equivalent SO_2 emission rates are listed in Table 8.

TABLE 7. ESTIMATED FLUE GAS COMPOSITIONS

FOR POWER UNITS WITHOUT EMISSION CONTROL FACILITIES

	Fuel and boiler type			
	Coal-fired boiler (horizontal frontal fired)			Oil-fired boiler (tangential fired)
	Sulfur content of fuel, % by wt (dry basis)			
Flue gas components (% by vol)	2.0	3.5	5.0	2.5
N_2	73.68	73.76	73.80	73.60
O_2	4.83	4.83	4.84	2.54
CO_2	12.44	12.31	12.20	11.96
SO_2	0.14	0.24	0.34	0.13
SO_3	0.0014	0.0024	0.0034	0.0013
NO_x (as NO)	0.06	0.06	0.06	0.02
HCl	0.01	0.01	0.01	-
H_2O	8.84	8.79	8.75	11.75
Fly Ash Loading				
gr/sft^3 (dry)	6.67	6.65	6.66	0.036
gr/sft^3 (wet)	6.08	6.06	6.08	0.032

TABLE 8. POWER PLANT FLUE GAS AND SO_2 RATES

Power plant size, MW	Type plant	Sulfur content of fuel, % (dry basis)	Gas flow to FGD systems, aft^3/min (300^oF)	Equivalent SO_2 emission rate to FGD systems, lb SO_2/hr
Coal-fired units				
200	Existing	3.5	652,000	10,610
200	New	3.5	631,000	10,270
500	Existing	3.5	1,577,000	25,690
500	New	2.0	1,539,000	14,500
500 (base case)	New	3.5	1,543,000	25,130
500	New	5.0	1,539,000	35,920
1,000	Existing	3.5	3,085,000	50,250
1,000	New	3.5	2,982,000	48,580
Oil-fired unit				
500	Existing	2.5	1,313,000	12,060

FGD System

Scrubber SO_2 removal requirements, design and redundancy, bypass, reheat, and other FGD design considerations are as follows:

Emission Standards--

Current EPA Federal Standards of Performance for New Stationary Sources (often called new source performance standards--NSPS) which define the maximum emission levels for new power plants in the United States are shown in Table 9 (Federal Register, 1971). The design assumed for this report is based on meeting the standard for particulate matter and SO_2 emission, rather than designing for a higher degree of removal. NSPS revisions, proposed in the Federal Register (1978), include a requirement of 85% SO_2 removal (24-hour average) with maximum emissions of 1.2 lb SO_2/MBtu.

TABLE 9. CURRENT EPA EMISSION STANDARDS FOR

NEW STEAM GENERATING FACILITIES

	Allowable emission, lb/MBtu heat input	
	Coal-fired unit	Oil-fired unit
Particulate matter	0.1	0.1
SO_2	1.2	0.8

Degree of Removal--

Because required SO_2 removal efficiencies vary depending on fuel type and sulfur content, case variations will show a range of 63% to 85% removal required to meet existing NSPS. The required removal efficiencies for fly ash and SO_2 are given in Table 10 for the fuels and sulfur levels considered. For all fuels evaluated, designs provide for limiting SO_2 emission to 1.2 lb SO_2/MBtu input (current NSPS). An additional case based on a 500-MW new coal-fired unit with 3.5% sulfur level has been prepared to show the effect of designing for 90% SO_2 removal.

TABLE 10. REQUIRED REMOVAL EFFICIENCIES

Sulfur content of fuel, %	Degree of particle removal, wt %	Degree SO_2 removal, %
Coal-fired units		
2.0	99.5	62.7
3.5	99.5	78.5
5.0	99.5	85.0
Oil-fired units		
2.5	-	69.8

SO_2 Scrubber--

Scrubbing system design assumes that technology used in each process is proven, has been demonstrated, and is not first-of-a-kind. No special redundancy provisions are assumed necessary for utility boiler - SO_2 scrubber system reliability.

Several methods are available to provide turndown capabilities of the control systems resulting from changes in power supply requirements including:

1. Multiple-scrubbing trains
2. Variable-flow control to individual scrubbers
3. Compartmentalized scrubbers
4. Individual scrubber bypasses
5. Connecting plenum ducts between trains

For this study, ESP ducts are assumed to exhaust to a common plenum connecting the scrubbing trains. Separate ducts from the plenum to each scrubbing train are equipped with dampers for individual scrubber shutoff for maintenance or power plant turndown. Because of the reliability implied in the assumption that these processes are based on proven technology, other special design provisions for individual scrubber shutdown are not provided. Bypass ducts for maintaining full power generation capacity during shutdown of one or more scrubbing trains are not provided.

The scrubber type for each process is:

Process	Scrubber type
Limestone	Mobile bed
Double alkali	Perforated plate tower
Citrate	Packed tower

Each scrubber system is designed with a presaturator for cooling and humidifying the flue gas. Absorption of flue gas components in the presaturator is assumed as follows:

Component	% removal
SO_2	5
SO_3	50
HCl	100
NO_x	0

In the limestone and double-alkali processes these compounds are disposed of in the waste stream along with the additional SO_2 removed in the absorption tower. In the citrate process the excess liquor from the presaturator drains into the bottom of the SO_2 absorber and is recycled to the presaturator for humidification and cooling of the flue gas. A liquor purge stream is pumped to a neutralization tank to which lime is added to control chloride contamination of the system. An SO_2 stripper is placed upstream from the neutralization tank to remove SO_2 from the purge stream and return it to the flue gas stream to allow as much sulfur as possible to be reclaimed from the system.

Each SO_2 scrubber is equipped with a chevron-type entrainment separator at the scrubber outlet. The use of an entrainment separator or mist eliminator in the scrubber is desirable for the following purposes.

1. To reduce the heat load on the stack gas reheater.
2. To decrease the deposition of liquid and entrained solids in ducts and equipment located downstream from the scrubber.
3. To reduce the amount of entrained solids emitted to the atmosphere.

The exit gas from the SO_2 absorber is assumed to contain water entrainment equivalent to 0.1% by weight of the wet gas mass rate.

Specific design conditions for SO_2 removal will vary from installation to installation corresponding to expected fluctuations in the fuel analysis and to differences in operating requirements. The operating conditions chosen for each base case scrubbing system in this study are presented in Table 11.

TABLE 11. ASSUMED OPERATING CONDITIONS FOR SCRUBBING SYSTEMS APPLIED TO NEW COAL-FIRED POWER UNITS

[500-MW units, 3.5% S in coal (dry basis), 1.2 lb SO_2/MBtu heat input allowable emission]

Operating conditions	Process Limestone	 Generic double alkali	 Citrate
Stoichiometry	1.32	1.0	-
Design gas velocity, ft/sec			
SO_2 scrubber	12.5	7.0	10.0
L/G, gal/kft^3			
Presaturator	4	4	4
SO_2 scrubber, recycle liquor	50	4	-
SO_2 scrubber, regenerated liquor	-	3	5
Design pressure drop, inches H_2O	8	3	15
Oxidation of removed SO_2 to $SO_4^{=}$, %	20	10	2

Reheat--

The need for stack gas reheat for corrosion reduction and plume buoyancy after aqueous scrubbing is recognized in the contemporary designs. Indirect steam reheat of the cleaned gas to 175°F is provided for all case variations except the oil-fired case. For the existing oil-fired power unit, direct stack gas reheat to 175°F is provided by mixing the combustion byproducts of an oil-fired reheater directly with the scrubbed gas.

Raw Materials--

Listed below are the raw materials that are used in the three desulfurization processes, with typical characteristics given for each.

1. Limestone
   Purchase size - 0 x 1/2 inch
   Analysis - 90% $CaCO_3$, 0.15% MgO, 4.85% inerts, 5% H_2O
   Limestone ground as 60% solids slurry
   Ground size - 70% minus 200 mesh
   Bulk density - 95 lb/ft^3

2. Lime
   Analysis - 95% CaO, 1% SiO_2, 2% MgO, 2% H_2O
   Size - 3/4 to 1-1/4 inch
   Bulk density - 55 lb/ft^3

3. Sodium carbonate
   Analysis - 99.8% Na_2CO_3 (58.36% Na_2O), 0.15% NaCl, 0.02% inerts, 0.03% H_2O
   Bulk density - 35.5 lb/ft^3

4. Citric acid
   Analysis - 99.5% to 100% purity
   Bulk density - 55 lb/ft^3

Solids Disposal--

One important design consideration for the limestone and double-alkali processes is the method for waste solids disposal. Two alternatives are investigated in this study.

1. Onsite pond disposal--The base case for the disposal of untreated limestone sludge is direct ponding of spent slurry from the scrubber in a clay-lined pond. The slurry is pumped to the pond at a solid concentration of 15%. In the double-alkali base case, a filter cake of calcium waste solids is reslurried to 15% solids and pumped to a clay-lined pond. The following assumptions are made for the pond.

   a. The pond is one mile from the scrubber system site and is located on flat land.

   b. The pond life is the same as power plant remaining life defined earlier in the power plant design premises.

c. The pond is sized and costed for the disposal of calcium wastes only. Fly ash disposal is not considered. Pond is designed to minimize total pond construction cost including cost of land by optimizing pond depth and excavation.

d. Pond is lined with 12 inches of impervious clay.

e. Settled sludge contains 40% by wt solids and 60% free water.

f. Closed-loop water cycle is maintained by returning excess pond water to the scrubber system.

g. Pond evaporation and seepage equals rainfall.

2. Trucking alternative--A special case is evaluated for the limestone and double-alkali processes in which the calcium solids are trucked to the disposal site. Each process is designed with a slurry dewatering system to produce a disposal cake containing 55% solids. Charges for land preparation by scraping are included. No stabilization is assumed; disposal cake is piled to a height of 30 feet. Further discussion of this alternative appears in the Systems Estimated section.

The disposal methods are those currently used. More stringent regulations for control of runoff pollution from solid wastes may be effected in the future and could affect some aspects of disposal area design and site maintenance. Although beyond the time frame projected in this report, such regulations could be an economic factor in waste disposal considerations.

ECONOMIC PREMISES

Economic evaluations of the three processes are divided into capital investment and revenue requirements. Criteria are assumed that define cost indexes; land, raw material, and utilities costs; capital charges; and other factors required for comparative estimates.

Capital Investment

Capital investment estimates represent projects beginning mid-1977 and ending mid-1980, with an average cost basis for scaling of mid-1979. Other project estimates may be scaled from mid-1979 to the midpoint of project expenditures. System design is assumed to require 6 to 12 months and construction 24 months. The overall project is assumed to be completed over a 30- to 36-month project schedule.

Estimates are based on cost information obtained from engineering-contracting, processing, and equipment companies; TVA equipment purchases and construction data; and authoritative publications on estimating and costs, such as Bauman (1964), Guthrie (1969), Peters and Timmerhaus (1968), Popper (1970), The Chemical Engineer's Handbook (Perry and Chilton, 1973), and The Richardson Rapid System (1978). Costs are projected (Table 12) for 1979 from historical annual Chemical Engineering (1974, 1975, 1976) cost indexes and published projections (Thorsen, 1972).

The battery limits of the SO_2 removal facility estimates began with the common plenum downstream of the ESP and include the stack gas reheaters downstream of the absorbers. The stack plenum is considered necessary to a power unit without SO_2 removal and is not included in the FGD cost. Costs for booster fans and ductwork required to circulate flue gas through the FGD system are included. Fly ash removal by ESP and fly ash disposal are considered power plant functions and are not included in investment or revenue requirement estimates. The ID fans located between the ESP and the first plenum are considered a part of the boiler unit and their cost is not included in the FGD evaluation. Neutralization of the chlorides purged from the flue gas in the citrate system presaturator is included in the FGD cost.

Other special provisions and assumptions used in the preparation of investment estimates are:

1. Spare pumps are provided to prevent operational shutdowns due to pump failure. For the limestone slurry and generic double-alkali processes, a spare pipeline is included for transport of sludge to the disposal area. No other spare equipment is included.

2. Process water utilization is based on closed-loop operation.

3. Indirect steam reheat of stack gases is assumed in all cases except for the existing oil-fired unit which utilizes direct oil-fired reheat.

4. Costs for the supplemental generation facilities for electricity used by the FGD system are not included in the capital investment. Compensation for derating of the boiler caused by FGD system electrical usage is added to the cost of electricity in the revenue requirement estimates.

5. Equipment, material, and construction-labor shortages with accompanying overtime pay incentive are not considered.

Direct Investment--

A detailed equipment list is prepared for the base case estimate which itemizes cost for materials and installation labor for each equipment item. In addition the cost of piping, insulation, ductwork, concrete foundations, excavation, structures, electrical, instrumentation, painting, and buildings required for each unit area are itemized.

TABLE 12. COST INDEXES AND PROJECTIONS

Year	1972	1973	1974	1975	1976[a]	1977[a]	1978[a]	1979[a]	1980[a]	1981[a]
Plant	137.2	144.1	165.4	182.4	197.9	214.7	232.9	251.5	271.6	293.3
Material[b]	135.4	141.9	171.2	194.7	210.3	227.1	245.3	264.9	286.1	309.0
Labor[c]	152.2	157.9	163.3	168.6	183.8	200.3	218.3	237.9	259.3	282.6

a. Projections. Although actual cost indexes are available for 1976-1978, TVA continues to use its projections for these years so that consistency with past estimates is maintained.

b. Same as index in Chemical Engineering for "equipment, machinery, supports."

c. Same as index in Chemical Engineering for "construction labor."

Services, utilities, and miscellaneous costs are calculated as 6% of direct investment minus pond construction costs. This is assumed to include such items as maintenance shops, stores, communications, security, and offices. Also included are costs for parking lots, walkways, landscaping, fencing, vehicles, and 1 mile of paved roads. Necessary electrical, fuel oil, steam, process water, fire and service water, and compressed air distribution facilities and instrument air generation facilities are also a part of this cost.

Indirect Investment--

In addition to direct costs which include equipment, installation, services and utilities, and pond construction, the indirect costs covering engineering design and supervision, architect and engineering contractor expenses, construction expense, contractor fees, and contingency are estimated for each project. The engineering design and supervision and contingency factors are based on proven design, not first-of-a-kind installation.

Engineering design and supervision (ED&S)--A technique that correlates the number of major equipment items with drafting room man-hour and engineering design costs is used to estimate this indirect investment factor. Battery-limit areas are included as a varying percentage of area cost. The percentage used is determined by commercial status and design reliability of the purchased unit. The formula used is:

Engineering design and supervision = (8900) (1.294) (number of major equipment pieces) + (5-25%) (battery-limit investment)

A separate procedure, based on pond construction expense, was developed to determine ED&S cost for the pond area.

$$\text{Pond engineering design and supervision} = (0.076)\ (a)^{0.67}$$

where (a) = direct pond investment in M$

The sum of these costs appears in the indirect investment display as ED&S for each process case variation.

Architect and engineering contractor expenses (A&E)--This factor is derived from the costs of engineering design and supervision. Twenty-five percent of the portion of ED&S associated with major equipment and battery-limit units is assumed for A&E. For cases involving disposal ponds, 10% of the ED&S associated with pond construction is estimated as additional A&E expense.

Construction expense--Construction expense is estimated based on direct investment by the following equation:

$$\text{Construction expense} = 0.25\ (b)^{0.83} + 0.13\ (c)^{0.83}$$

where b = direct investment in M$ excluding pond investment costs

c = direct pond cost in M$

Contractor fees--A correlation between contractor fees and direct investment is used to estimate the cost of contractor fees.

Contractor fees = $0.096\ (d)^{0.76}$

where d = total direct investment in M$

Contingency--Contingency is assumed to be 20% of the sum of direct investment, engineering design and supervision costs, architect and engineering contractor expenses, construction expense, and contractor fees.

Other Capital Charges--

Total fixed investment is defined as the sum of the investment costs by area--services, utilities, and miscellaneous; pond construction; indirect investments; and contingency. Allowance for startup and modification is estimated to be 10% of the total fixed investment excluding pond construction.

Interest during construction is estimated to be 12% of the total fixed investment. This percentage is calculated as the simple interest which would be accumulated at a 10% per year rate assuming an incremental capital structure of 60% debt to 40% equity and a 3-year project expenditure schedule as shown in Table 13.

TABLE 13. PROJECT EXPENDITURE SCHEDULE

	Year 1	Year 2	Year 3	Total
Fraction of total expenditure as borrowed funds	0.15	0.30	0.15	0.60
Simple interest as 10%/yr as % of total expenditure				
Year 1 debt	1.5	1.5	1.5	4.5
Year 2 debt	-	3.0	3.0	6.0
Year 3 debt	-	-	1.5	1.5
Accumulated interest as % of total expenditure	1.5	4.5	6.0	12.0

Land--

Total land requirements including disposal pond area are assumed purchased at the beginning of the project. Cost of land is estimated at $3,500 per acre.

Working Capital--

Working capital consists of (1) money invested in raw materials, supplies and finished products carried in stock, and semifinished products in the process of being manufactured, (2) accounts receivable, (3) cash retained for payment of operating expenses, such as salaries, wages, and raw material puschases, (4) accounts payable, and (5) taxes payable. For these premises, working capital is defined as the equivalent of 3 weeks of raw material costs, 7 weeks of direct costs, and 7 weeks of overhead costs.

Case Variations--

Each area of the base case direct investment is analyzed and adjusted as necessary to reflect required modifications in process design for the case variations. For example, indirect steam reheat investment costs are replaced with direct oil-fired reheat investment costs for the existing oil-fired unit. In the citrate process, the chloride purge is eliminated for the existing oil-fired case. Modifications are made in the amount of ductwork provided for all existing units.

The adjusted area investment subtotal is scaled exponentially according to the relative throughput, using a weighted average scaling exponent calculated from the base case investment breakdown. Flue gas processing areas are scaled on the basis of relative gas throughput; byproduct processing areas are scaled on the basis of relative sulfur throughput. Table 14 shows the relative quantities of gas and sulfur which must be processed for each of the case variations in comparison with the base case quantities. The direct, indirect, fixed, and total capital investments are then determined by the same procedure described for the base case investment.

Revenue Requirements

Annual Revenue Requirements--

Average annual revenue requirements for each case variation are calculated under regulated economics assuming 7,000 hours of operation per year. Process operation schedules are assumed to be the same as the power plant operating profiles and remaining life assumptions given in the power plant design premises. Operating costs for removal and disposal of fly ash are not included.

Direct Costs--

Raw materials, operating labor and supervision, utilities, maintenance costs, and analyses have been projected to 1980 dollars to reflect a mid-1980 scrubbing unit startup. The projected unit costs for raw materials, labor, and utilities are shown in Table 15. All tonnages are expressed in short tons. Raw material costs are the delivered costs to a Chicago power plant location; labor costs are rates for the midwestern area (Illinois, Indiana, Kentucky). Unit costs for steam and electricity generated by the power plant are based on acutal production cost including labor, fuel, depreciation, rate base return on investment, and taxes.

TABLE 14. RELATIVE QUANTITIES OF GAS AND SULFUR TO BE PROCESSED IN COMPARISON WITH THE BASE CASE QUANTITIES

	Relative throughput rate, %	
	Gas	Sulfur removed
Coal-Fired Power Unit		
1.2 lb SO_2/MBtu heat input allowable emission		
200 MW E 3.5% sulfur	42.22	42.22
200 MW N 3.5% sulfur	40.89	40.89
500 MW E 3.5% sulfur	102.22	102.22
500 MW N 2.0% sulfur	100.00	46.01
500 MW N 3.5% sulfur	100.00	100.00
500 MW N 5.0% sulfur	100.00	153.81
1,000 MW E 3.5% sulfur	200.00	200.00
1,000 MW N 3.5% sulfur	193.33	193.33
Solids disposal by trucking		
500 MW N 3.5% sulfur	100.00	100.00
90% SO_2 removal		
500 MW N 3.5% sulfur	100.00	113.92
Oil-Fired Power Unit		
0.8 lb SO_2/MBtu heat input allowable emission		
500 MW E 2.5% sulfur	84.70	44.08

TABLE 15. PROJECTED 1980 UNIT COSTS
FOR RAW MATERIALS, LABOR, AND UTILITIES

	$/unit
Raw Materials	
Limestone	7.00/ton
Lime	42.00/ton
Soda ash	90.00/ton
Citric acid	1,340.00/ton
Natural gas	3.50/kft^3
Catalyst	_[a]
Labor	
Operating labor	12.50/man-hr
Analyses	17.00/man-hr
Trucking landfill	17.00/man-hr
Utilities	
Fuel oil (No. 6)	0.40/gal
Steam (500 psig)	2.00/MBtu
Process water (citrate)[b]	0.06/kgal
Process water[b]	0.12/kgal

	200 MW	500 MW	1,000 MW
Electricity	0.031/kWh	0.029/kWh	0.028/kWh

---

a. Unit costs supplied by C&I Girdler.

b. Varies according to water volume requirements which are process dependent.

Quantities of raw materials and utilities required by each process, except for electricity, are derived from the base case material balance. Electricity requirements are compiled from motor horsepower and equivalent kilowatt usage as defined in the base case equipment description. The amount of equipment in each process area and the difficulty of operation are considered in estimating the hours of operating labor and supervision for each process. Labor estimates for laboratory analysis are based on the quantities of materials which must be analyzed to maintain quality control.

Maintenance costs are estimated on the basis of direct investment and are varied for each process as a function of unit size to reflect economy of scale. Maintenance percentages are also varied for each process according to projected relative process complexity and historical experience, when available. Table 16 shows the estimated overall annual maintenance factors which are applied to the total direct investment, minus pond construction costs, for each process, corresponding to an annual operating schedule of 7,000 hours. Pond maintenance for the limestone and double-alkali processes is estimated as 3% of the pond construction cost.

TABLE 16. ESTIMATED OVERALL ANNUAL MAINTENANCE COSTS

Process	% of direct investment excluding pond construction[a] 200 MW	500 MW	1,000 MW
Limestone	9	8	7
Double alkali	5	4	3
Citrate	7	6	5

a. Pond maintenance is estimated as 3% of pond construction cost.

Indirect Costs--

In estimating revenue requirements for FGD systems, the method chosen for financing the system--regulated power industry practice, nonregulated chemical industry practice, or a combination of the two--has a major effect on capital charge items such as depreciation and taxes. This study is based on regulated utility economics. The capital charges included in the indirect revenue requirement costs are applied as average charges which include depreciation, interim replacements, insurance, cost of capital, and taxes. These charges vary with remaining life of the power plant. A breakdown of the capital charges is given in Table 17. The depreciation rate is straight line, based on the remaining life of the power plant after the FGD system is installed.

In estimating the regulated capital charges associated with stack gas scrubbing, the conventional method of considering the overall life of the power plant is used. FERC (1968, 1969) recognized the conclusion of the National Power Survey that a 30-year service life is reasonable for steam-electric plants. Because some equipment items have life spans less than 30 years, however, an allowance factor, designated interim replacements, is included. Use of this allowance, following FERC recommended practice, provides for financing the cost of replacing short-lived units. Although an average allowance of about 0.35% of the total investment is normally provided, a somewhat larger allowance factor is used for new units in this study to account for the unknown life span of FGD facilities. An insurance allowance is also included in the capital charges. Property taxes, the fourth item of the capital charge rate applied to the original investment, are estimated at 1.5% of the total depreciable capital investment.

TABLE 17. ANNUAL CAPITAL CHARGES FOR POWER INDUSTRY FINANCING

Years remaining life	Percentage of total depreciable capital investment		
	30	25	20
Depreciation (straight line, based on years remaining life of power unit)	3.3	4.0	5.0
Interim replacements (equipment having less than 30-year life)	0.7	0.4	-
Insurance	0.5	0.5	0.5
Property taxes	1.5	1.5	1.5
Total rate applied to original investment	6.0	6.4	7.0

	Percentage of unrecovered capital investment[a]
Cost of capital (capital structure assumed to be 60% debt and 40% equity)	
Bonds at 10% interest	6.0
Equity[b] at 14% return to stockholder	5.6
Income taxes (Federal and State)[c]	5.6
Total rate applied to depreciation base	17.2[d]

a. Original investment yet to be recovered or "written off."
b. Contains retained earnings and dividends.
c. Federal and State income taxes are assumed to have the same impact on capital cost as return on equity.
d. Applied on an average basis, the total annual percentage of original fixed investment for new (30-yr) plants would be 6.0% + 1/2(17.2%) = 14.6%.

Debt to equity ratio is another component of capital charges for which variations of ratios may be expected. FERC data (1972, 1974) indicate that the long-term debt for privately owned electric utilities varied only slightly from 51.5% to 54.8% of total capitalization during the period 1965-1973. Recent economic trends have affected the incremental debt to equity ratio, however, as utilities are forced to depend more and more on bonds and bank loans for project funding. The capital structure for this study is assumed to be 60% debt and 40% equity, with the interest rate for bonds assumed to be 10% and the return to stockholders 14%. Federal and State income taxes are assumed to have the same effect on capital cost as return on equity (5.6%).

The procedure for calculating plant, administrative, and marketing overheads can vary from company to company. Based on several cost estimating sources used in this study, the following methods are used to estimate overheads.

1. Plant overhead is estimated as 50% of the total conversion costs less utilities. This method has been selected to avoid overcharging processes which are energy intensive.

2. Administrative overhead is estimated as 10% of the operating labor and supervision cost.

3. Marketing of FGD byproducts is defined as sales to a distributor, shipping costs excluded, and marketing overheads are estimated on the basis of the relative difficulty in marketing the various products of the processes studied. For the citrate process, marketing overhead is estimated as 10% of the revenue collected from the sale of sulfur.

The citrate process is the only system evaluated in this study that produces a salable byproduct. In the calculation of citrate annual and lifetime economics, credit from the sale of sulfur ($40 per short ton) is deducted from the yearly projection of revenue requirement to give the net effect of the FGD process on the cost of power.

Case Variations--

Raw materials and utilities for the case variations are scaled from the requirements indicated on the detailed base case revenue requirement summary. Utilities such as reheat energy and fan electricity are scaled proportionately to the relative gas rate for each case variation; raw materials and utilities such as absorbent and electricity for the sulfur processing areas are scaled proportionately to the relative sulfur rate for the various cases. Annual costs for raw materials and utilities are then calculated by applying the unit costs to the scaled annual usage rates.

Lifetime Revenue Requirements--

Because of the typical declining load of most power units over their life, lifetime revenue requirements are better measures of the overall process costs than are annual revenue requirements. Since annual revenue requirements vary each year as the rate base declines because of depreciation writeoff and with any changes in on-stream time of the power unit, it is desirable to have a year-to-year tabulation of annual and cumulative lifetime revenue requirements for any given case. For a comparison that recognizes the time value of money, the declining annual revenue requirements for each process over the life of the plant should be discounted at the cost of money (11.6% for this study) to the initial year of operation. The total of these costs can be compared directly or can be converted to equivalent unit costs for comparison with the premium expected for low-sulfur fuels.

For each of the case variations of the three processes, lifetime costs are projected corresponding to the declining operating profile established (Table 5). Year-by-year revenue requirements included in the lifetime projections are calculated by computer in the same manner as annual revenue requirements, with the exception that capital charges are based on the declining undepreciated investment. Since the regulated return on investment profitability is included in the year-by-year projections of revenue requirements, any revenue received from sale of byproducts can be applied toward reducing these yearly costs.

SYSTEMS ESTIMATED

Process description, material balance, flow diagram, layout drawings, and equipment requirements have been prepared for each of the three processes evaluated. Each process is divided into major functional areas to facilitate comparisons of investment and revenue requirements for similar processing steps. Equipment lists follow the area-by-area pattern with material costs presented in 1979 dollars for each item. The additional items of cost in each area are piping and transport lines, ductwork, concrete foundations, excavation and site preparation, structure, electrical wiring, instrumentation, buildings, and pond construction.

LIMESTONE SLURRY PROCESS

The limestone slurry process for desulfurization of flue gas (Figure 1) assumes fly ash removal by ESP. A common plenum is placed downstream from the ESP and the power plant ID fans to distribute the gas to the absorbers. Booster fans are placed between the plenum and the absorber to overcome the pressure drop created by the FGD system (Figure 2).

Incoming 0 x 1-1/2 inches limestone is received either by truck or rail and conveyed to a 30-day storage pile located about 150 feet from the grinding facilities (Figure 3). The limestone is reduced to about 0 x 3/4 inches using gyratory crushers, wet-ground to 70% minus 200 mesh in two parallel ball mills, and stored as a 60% solids slurry in a feed tank with 8-hour storage capacity. The slurry feed tank is located near the absorber system (Figure 4) about 1500 ft from the limestone preparation area.

Makeup limestone slurry is combined with scrubber effluent slurry and recycle pond water in the absorber hold tank to control the concentration of the recirculating slurry at approximately 15% solids. Flue gas is cooled in a presaturator with recycle slurry and fed to the mobile-bed absorbers. Limestone slurry circulates through the absorbers where it reacts with the SO_2 in the cooled flue gas. The absorbers are equipped with chevron-type entrainment separators with provisions for upstream and downstream wash with fresh makeup water to control entrainment carryover in the gas stream. Scrubber outlet gas is reheated to 175°F by indirect steam heat before entering the stack.

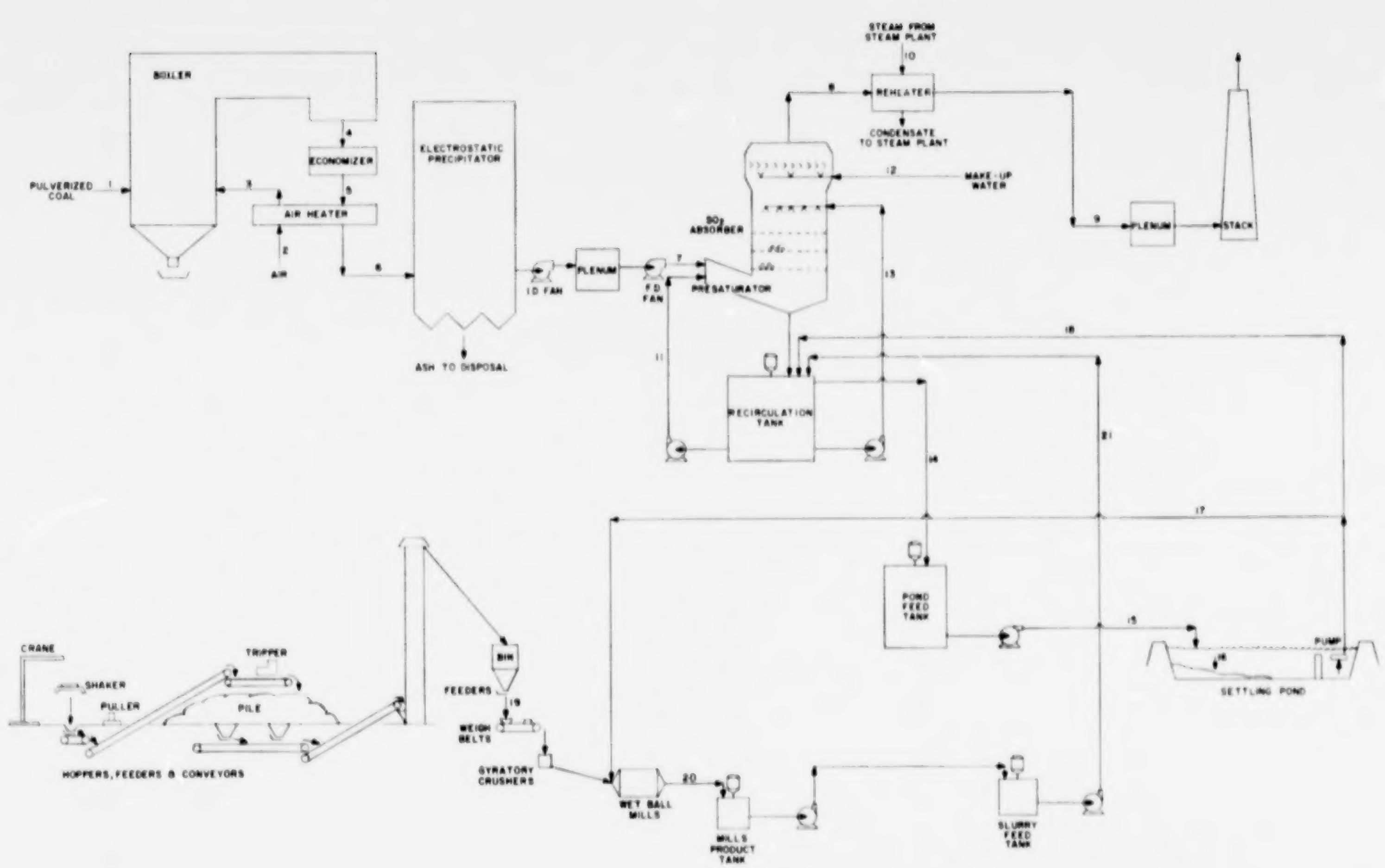
BOILER
PULVERIZED COAL
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
AIR
ECONOMIZER
AIR HEATER
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
I D FAN
PLENUM
F D FAN
SO_2 ABSORBER
PRESATURATOR
STEAM FROM STEAM PLANT
REHEATER
CONDENSATE TO STEAM PLANT
MAKE-UP WATER
PLENUM
STACK
RECIRCULATION TANK
POND FEED TANK
SETTLING POND
PUMP
CRANE
SHAKER
PULLER
TRIPPER
PILE
HOPPERS, FEEDERS & CONVEYORS
BIN
FEEDERS
WEIGH BELTS
GYRATORY CRUSHERS
WET BALL MILLS
MILLS PRODUCT TANK
SLURRY FEED TANK

Figure 1. Limestone slurry process. Base case flow diagram.

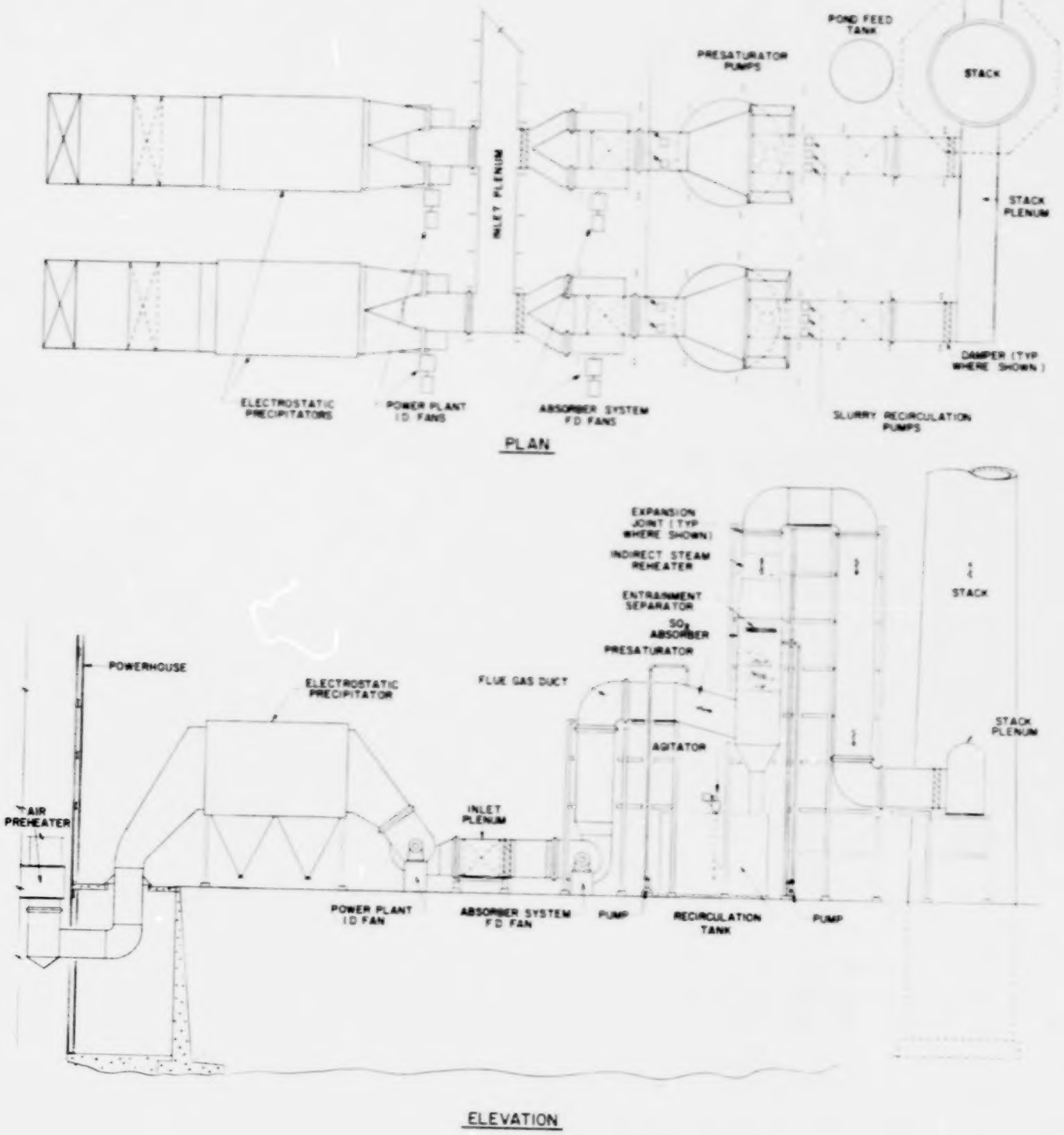
POND FEED TANK
PRESATURATOR PUMPS
STACK
INLET PLENUM
STACK PLENUM
DAMPER (TYP WHERE SHOWN)
ELECTROSTATIC PRECIPITATORS
POWER PLANT I.D FANS
ABSORBER SYSTEM F.D FANS
SLURRY RECIRCULATION PUMPS
PLAN
EXPANSION JOINT (TYP WHERE SHOWN)
INDIRECT STEAM REHEATER
ENTRAINMENT SEPARATOR
SO2 ABSORBER
PRESATURATOR
STACK
POWERHOUSE
ELECTROSTATIC PRECIPITATOR
FLUE GAS DUCT
AGITATOR
STACK PLENUM
AIR PREHEATER
INLET PLENUM
POWER PLANT I.D FAN
ABSORBER SYSTEM F.D FAN
PUMP
RECIRCULATION TANK
PUMP
ELEVATION

Figure 2. Limestone slurry process. Mobile-bed scrubber system base case plan and elevation.

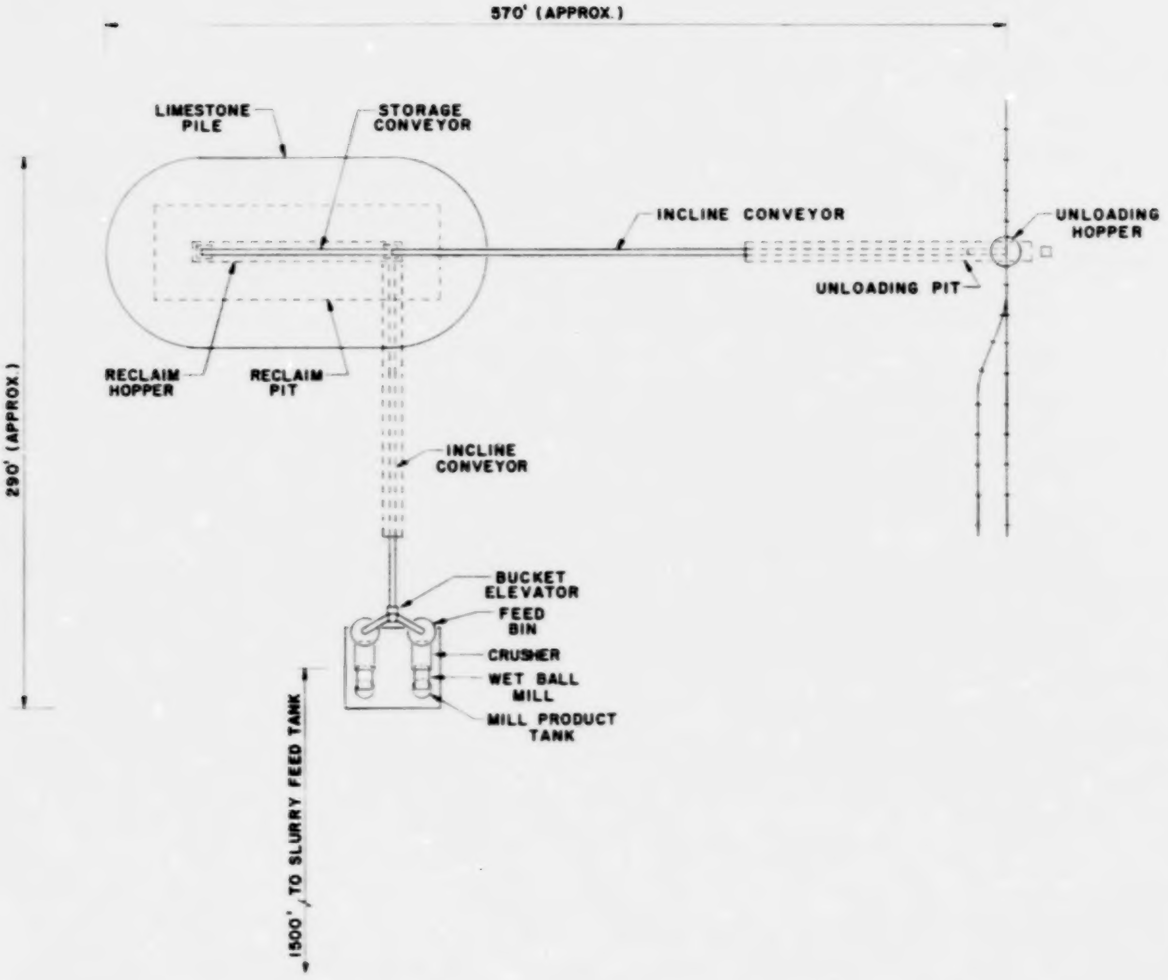
570' (APPROX.)
LIMESTONE PILE
STORAGE CONVEYOR
INCLINE CONVEYOR
UNLOADING HOPPER
UNLOADING PIT
RECLAIM HOPPER
RECLAIM PIT
290' (APPROX.)
INCLINE CONVEYOR
BUCKET ELEVATOR
FEED BIN
CRUSHER
WET BALL MILL
MILL PRODUCT TANK
1500', TO SLURRY FEED TANK

Figure 3. Limestone slurry process. Base case materials handling and feed preparation system layout.

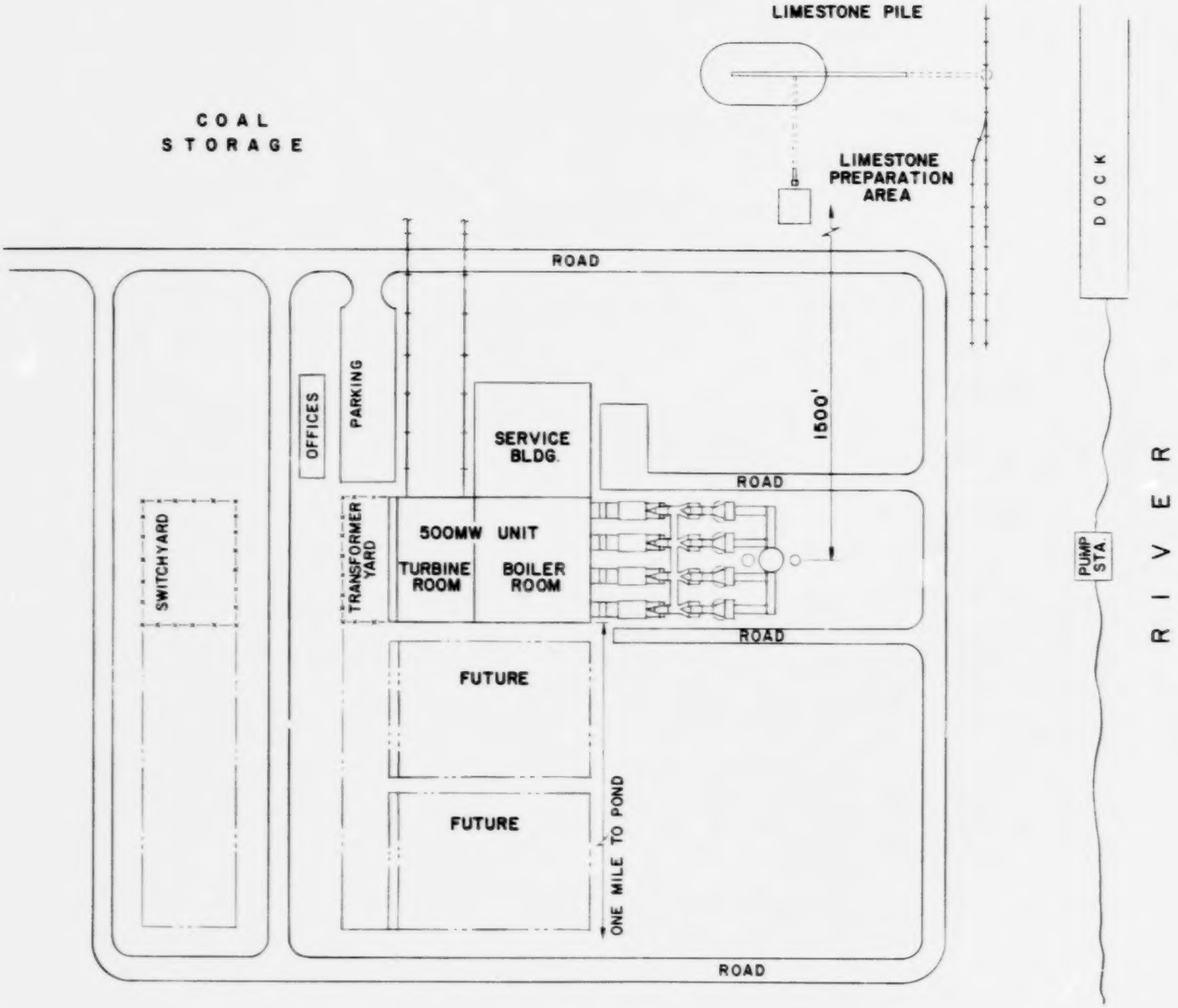
LIMESTONE PILE
COAL STORAGE
LIMESTONE PREPARATION AREA
DOCK
ROAD
PARKING
OFFICES
SERVICE BLDG.
1500'
ROAD
SWITCHYARD
TRANSFORMER YARD
500MW UNIT
TURBINE ROOM
BOILER ROOM
PUMP STA
RIVER
ROAD
FUTURE
FUTURE
ONE MILE TO POND
ROAD

Figure 4. Limestone slurry process. Base case overall plot plan.

A bleedstream from the recirculation tank is fed to the pond feed tank and the spent slurry is pumped to the onsite pond where the solids in the slurry settle to form a sludge containing approximately 40% solids. Pond supernate is recycled to the wet ball mills and the absorber effluent hold tank to maintain closed-loop operation. A special case is evaluated in which the spent slurry is pumped to a slurry dewatering system to produce a disposal cake containing 60% solids; the cake is trucked to a disposal site located 1 mile from the scrubbing facilities. Slurry dewatering includes thickener and rotary drum filters. Overflow from the thickener is recycled to the wet ball mills and to the absorber recirculation tanks.

A material balance for the base case limestone slurry scrubbing process is shown in Table 18 and a detailed equipment list by area for the system is presented in Table 19.

Major Process Areas

The limestone slurry process is divided into the following operating areas.

1. Materials handling. Facilities for receiving raw limestone, a storage stockpile, and in-process limestone storage are included in this area.

2. Feed preparation. This area includes the equipment for converting raw limestone to a 70% minus 200 mesh, 60% solids slurry for feed to the scrubbers.

3. Gas handling. Included in this area is one inlet flue gas plenum interconnecting each of the four flue gas ducts which feed the absorbers and four FD fans which overcome the pressure drop in the FGD systems.

4. SO_2 absorption. Four mobile-bed absorbers with presaturators, recirculation tanks, and pumps are included.

5. Stack gas reheat. Equipment in this area includes indirect steam reheaters and soot blowers for the coal variations. The oil-fired unit is designed with one direct oil-fired reheater per duct which discharges hot combustion gases directly into the duct.

6. Solids disposal. Equipment in this area consists of one pond feed tank with agitator and pond feed and pond return pumps.

Storage Capacity

Storage requirements for raw materials and allowances for in-process streams are listed below.

Raw materials:
Limestone storage - 30 days stockpile

In-process storage:
Crusher feed bin - 8 hours
Mills product tank - 20 minutes
Slurry feed tank - 8 hours
Pond feed tank - 15 minutes
Recirculation tanks - 10 minutes each (includes sufficient surge capacity for shutdown of scrubbers)

Solids Disposal

In the case variations which dispose of FGD waste solids by ponding, spent slurry containing 15% solids is pumped from an agitated pond feed tank to a disposal pond located 1 mile from the scrubbing facilities where the calcium salts settle to a sludge containing 40% solids. For the base case (500-MW, new, 3.5% sulfur, coal-fired unit), the field line transporting slurry to the pond is a 12-inch rubber-lined, carbon steel pipe. A spare field line to the pond is included and both lines are trenched. The recycle pond waterline for the base case is 10 inches, unlined, carbon steel pipe; no spare is included.

Pond Construction--

Optimum pond dimensions and costs for each case are calculated by computer based on a square configuration with a diverter dike three-fourths the length of a side. A pond construction diagram is shown in Figure 5. Assuming level land for the pond site, total pond depth for base case is 19.6 feet with an excavation depth of 3.0 feet. The pond is lined with 12 inches of impervious clay assumed to be excavated at the site. Pond areas for each case variation are listed in Table 20.

Trucking Alternative--

A case variation has been prepared on base case conditions which produces a filter cake disposed of by piling. A thickener and rotary drum filters which dewater the slurry to a 55% solids cake are added to the system after the pond feed tank (now the thickener feed tank). The cake is moved by conveyor to an in-process waste pile where wheeled loaders transfer the solids to dump trucks for transport to a disposal area 1 mile from the scrubbing facilities. Assuming level land, the disposal site is scraped to clay base and a ditch 10 feet wide and 10 feet long is dug around the perimeter of the site runoff to the ash pond. Waste solids are piled 30 feet high using a grader, a dozer, and a towed roller.

A detailed description of the economics of lime-limestone waste disposal has been published (Barrier, et al., 1978).

TABLE 18. LIMESTONE SLURRY PROCESS

MATERIAL BALANCE - BASE CASE

	Stream No.	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Combustion air to boiler	Gas to economizer	Gas to air heater
1	Total stream, lb/hr	428,600	4,546,200	4,101,800	4,516,100	4,516,100
2	sft^3/min (60^{o}F)		1,005,000	906,700	958,000	958,000
3	Temperature, ^{o}F		80	535	890	705
4	Pressure, psig					
5	gpm					
6	Specific gravity					
7	pH					
8	Undissolved solids, %					
9						
10						

	Stream No.	6	7	8	9	10
	Description	Gas to electrostatic precipitator	Gas to presaturator	Gas to reheater	Gas to stack	Steam to reheater
1	Total stream, lb/hr	4,960,400	4,905,800	5,108,100	5,108,100	93,070
2	sft^3/min (60^{o}F)	1,056,000	1,056,000	1,127,200	1,129,000	
3	Temperature, ^{o}F	300	300	127	175	470
4	Pressure, psig					500
5	gpm					
6	Specific gravity					
7	pH					
8	Undissolved solids, %					
9						
10						

	Stream No.	11	12	13	14	15
	Description	Recycle slurry for saturation	Makeup water to absorber	Recycle slurry to absorber	Overflow to pond feed tank	Slurry to pond
1	Total stream, lb/hr	2,803,900	292,100	35,023,500	360,000	360,000
2	sft^3/min (60^{o}F)					
3	Temperature, ^{o}F					
4	Pressure, psig					
5	gpm	5,094	584	63,628	654	654
6	Specific gravity	1.1		1.1	1.1	1.1
7	pH	5.3		5.3		
8	Undissolved solids, %	15		15	15	15
9						
10						

	Stream No.	16	17	18	19	20
	Description	Settled sludge	Pond water to wet ball mill	Pond water to recirculation tank	Limestone to weigh feeder	Slurry to mills product tank
1	Total stream, lb/hr	135,000	26,400	198,600	45,200	71,600
2	sft^3/min (60^{o}F)					
3	Temperature, ^{o}F					
4	Pressure, psig					
5	gpm	205	53	397		89
6	Specific gravity	1.32				1.61
7	pH					
8	Undissolved solids, %	40				60
9						
10						

(continued)

TABLE 18 (continued)

	Stream No.	21				
	Description	Limestone slurry to recirculation tank				
1	Total stream, lb/hr	71,600				
2	sft^3/min (60°F)					
3	Temperature, $^{\circ}$F					
4	Pressure, psig					
5	gpm	89				
6	Specific gravity	1.61				
7	pH					
8	Undissolved solids, %	60				
9						
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TABLE 19. LIMESTONE SLURRY PROCESS

BASE CASE EQUIPMENT LIST DESCRIPTION AND COST

Area 1--Materials Handling

	Item	No.	Description	Total material cost, 1979 $
1.	Car shaker	1	Top mounting with crane	9,000
2.	Car puller	1	25 hp with 5 hp return	50,000
3.	Hopper, limestone unloading	1	12 ft x 20 ft x 2 ft bottom, 20 ft deep, 4,800 ft^3, carbon steel	9,300
4.	Feeder, limestone unloading	1	Vibrating pan 42 in. wide x 60 in. long, 3 hp, 250 tons/hr	4,800
5.	Conveyor, limestone unloading	1	Belt 36 in. wide x 10 ft long, 5 hp, 250 tons/hr, 130 ft/min	2,200
6.	Conveyor, limestone stocking (incline)	1	Belt 36 in. wide x 320 ft long, 30 hp, 15° slope, 250 tons/hr, 130 ft/min	48,000
7.	Conveyor, limestone stocking	1	Belt 36 in. wide x 200 ft long, 7-1/2 hp, 250 tons/hr, 130 ft/min	30,000
8.	Tripper	1	5 hp, 30 ft/min	14,800
9.	Mobile equipment	1	Scraper tractor, 22 to 24 yd^3 capacity	181,000
10.	Hopper, reclaim	2	7 ft x 7 ft, 4 ft deep, 60° slope, carbon steel	11,200
11.	Feeder, live limestone storage	2	Vibrating pan 24 in. wide x 40 in. long, 1 hp, 12 tons/hr	7,000
12.	Pump, tunnel sump	1	Vertical, 60 gpm, 70 ft head, 5 hp, carbon steel, neoprene lined	3,400
13.	Conveyor, live limestone feed	1	Belt 30 in. wide x 100 ft long, 2 hp, 100 tons/hr, 60 ft/min	14,400
14.	Conveyor, live limestone feed (incline)	1	Belt 30 in. wide x 190 ft long, 5 hp, 35 ft lift, 100 tons/hr, 60 ft/min	26,600

(continued)

TABLE 19 (continued)

Item	No.	Description	Total material cost, 1979 $
15. Elevator, live limestone feed	1	Continuous, bucket, 12 in. x 8 in. x 11-3/4 in., 20 hp, 75 ft lift, 100 tons/hr, 160 ft/min	30,800
16. Bin, crusher feed	1	17 ft dia x 17 ft high, w/cover, 3/8 in. carbon steel	13,800
17. Dust collecting system	1	Cyclone, 2,100 aft^3/min, motor driven fan	5,900
18. Dust collecting system	1	Cyclone, 6,200 aft^3/min, motor driven fan	14,200
19. Dust collecting system	1	Bag filter, polypropylene bag, 14,400 aft^3/min, automatic shaker system (1/2 cost in feed preparation area)	10,000
Subtotal			486,400

Area 2--Feed Preparation

Item	No.	Description	Total material cost, 1979 $
1. Feeder, limestone bin discharge	2	Vibrating, 12 tons/hr, w/cover, carbon steel	1,900
2. Feeder, crusher	2	Weigh belt, 18 in. wide x 14 ft long, 1-1/2 hp, 12 tons/hr	15,800
3. Crusher	2	Gyratory, 0 x 1-1/2 to 3/4 in., 50 hp, 12 tons/hr	54,000
4. Ball mill	2	Wet, open system, 8 ft dia x 13 ft long, 350 hp, 300 tons/day	393,100
Ball charge			31,100
5. Hoist	1	Electric, 5 ton	8,300
6. Tank, mills product	1	9 ft dia x 5 ft high, 2,350 gal, open top, four 9 in. baffles, agitator supports, carbon steel	1,300
Lining		1/4 in. neoprene lining	1,100

(continued)

TABLE 19 (continued)

Item	No.	Description	Total material cost, 1979 $
7. Agitator, mills product tank	1	36 in. dia, 10 hp, neoprene coated	12,000
8. Pump, mills product tank	2	Centrifugal, 89 gpm, 60 ft head, 7-1/2 hp, carbon steel, neoprene lined	5,400
9. Tank, slurry feed	1	18 ft dia x 22 ft high, 42,800 gal, open top, four 18 in. baffles, agitator supports, carbon steel	10,500
Lining		1/4 in. neoprene lining	9,800
10. Agitator, slurry feed tank	1	3 turbines, 72 in. dia, 75 hp, neoprene coated	58,000
11. Pump, slurry feed tank	2	Centrifugal, 89 gpm, 60 ft head, 7-1/2 hp, carbon steel, neoprene lined	5,400
12. Dust collecting system	1	Cyclone, 8,200 aft^3/min, motor-driven fan	16,300
13. Dust collecting system	1	Bag filter, polypropylene bag, 14,400 aft^3/min, automatic shaker system (1/2 cost in materials handling area)	10,000
Subtotal			634,000

Area 3--Gas Handling

Item	No.	Description	Total material cost, 1979 $
1. Fans	4	Forced draft, 13 in. static head, 890 rpm, 1,250 hp, fluid drive, double width, double inlet	812,000
Subtotal			812,000

(continued)

TABLE 19 (continued)

Area 4--SO_2 Absorption

	Item	No.	Description	Total material cost, 1979 $
1.	SO_2 absorber	4	Mobile-bed scrubber, 31 ft long x 14 ft wide x 40 ft high, 1/4 in. carbon steel, neoprene lining; 316 SS grids, nitrile foam spheres, FRP spray headers, 316SS chevron vane entrainment separator	2,813,700
2.	Tank, recirculation	4	34 ft dia x 26 ft high, 173,500 gal, open top, four 34 in. baffles, agitator supports, carbon steel	85,600
	Lining		1/4 in. neoprene lined	79,800
3.	Agitator, recirculation tank	4	100 in. dia, 50 hp, neoprene coated	185,600
4.	Pump, presaturator	6	Centrifugal, 1,274 gpm, 105 ft head, 75 hp, carbon steel, neoprene lined	58,000
5.	Pump, makeup water	2	Centrifugal, 1,168 gpm, 150 ft head, 75 hp, carbon steel	15,300
6.	Pump, slurry recirculation	10	Centrifugal, 7,954 gpm, 105 ft head, 500 hp, carbon steel, neoprene lined	294,000
7.	Soot blowers	40	Air, retractable	260,000
	Subtotal			3,792,000

Area 5--Reheat

	Item	No.	Description	Total material cost, 1979 $
1.	Reheater	4	Steam, tube type, 3,600 ft^2, one-half tubes made of Inconel 625 and one-half made of Cor-Ten	856,000
2.	Soot blowers	20	Air, retractable	130,000
	Subtotal			986,000

(continued)

TABLE 19 (continued)

Area 6--Solids Disposal

	Item	No.	Description	Total material cost, 1979 $
1.	Tank, pond feed	1	12 ft dia x 15 ft high, 12,700 gal, open top, four 12 in. baffles, agitator supports, carbon steel	4,100
	Lining		1/4 in. neoprene lining	3,700
2.	Agitator, pond feed tank	1	2 turbines, 66 in. dia, 15 hp, neoprene coated	19,500
3.	Pumps, pond feed	2	Centrifugal, 654 gpm, 100 ft head, 50 hp, carbon steel, neoprene lined	12,800
4.	Pumps, pond return	2	Centrifugal, 450 gpm, 100 ft head, 30 hp, carbon steel	6,900
	Subtotal			47,000

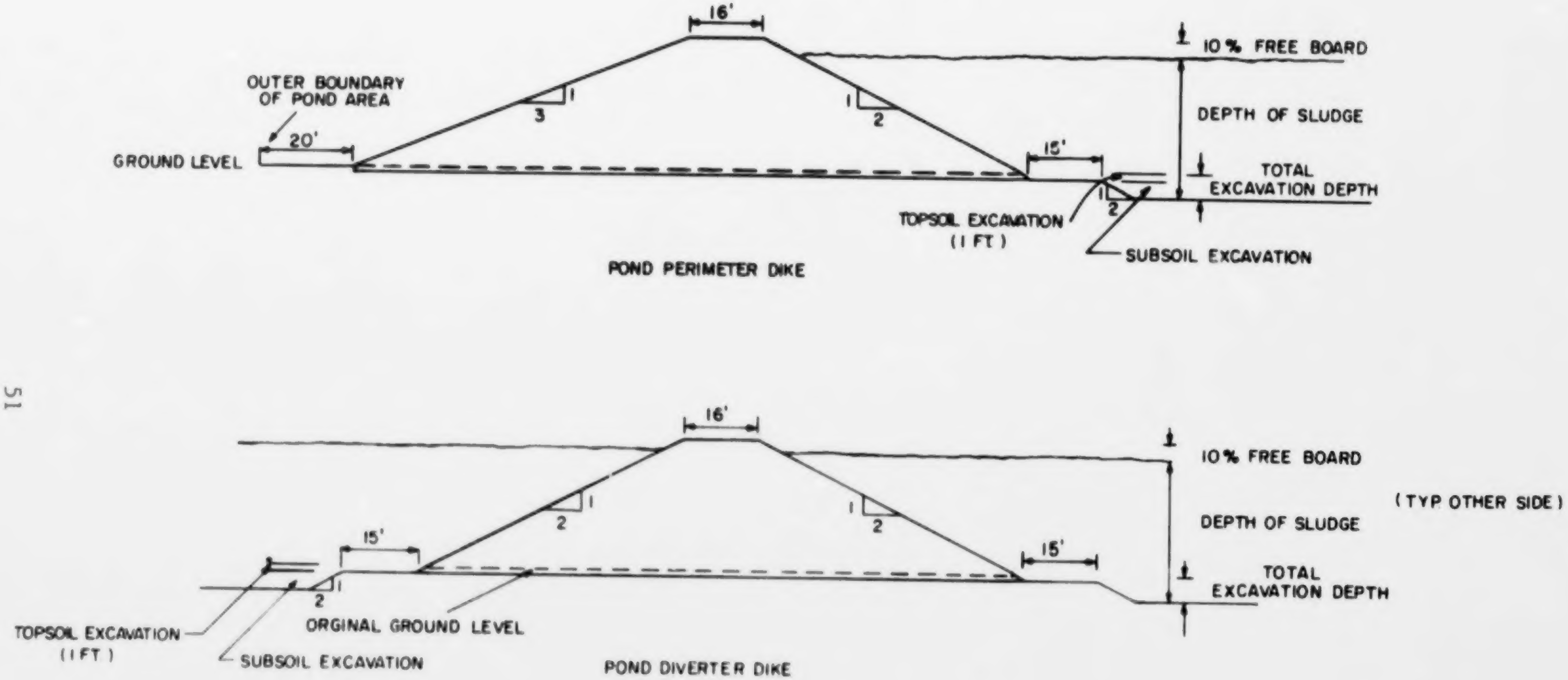

16'
10% FREE BOARD
OUTER BOUNDARY OF POND AREA
1
3
1
2
DEPTH OF SLUDGE
20'
GROUND LEVEL
15'
TOTAL EXCAVATION DEPTH
1
2
TOPSOIL EXCAVATION (1 FT)
SUBSOIL EXCAVATION
POND PERIMETER DIKE
16'
10% FREE BOARD
1
2
1
2
(TYP OTHER SIDE)
DEPTH OF SLUDGE
15'
15'
TOTAL EXCAVATION DEPTH
2
1
TOPSOIL EXCAVATION (1 FT)
ORGINAL GROUND LEVEL
SUBSOIL EXCAVATION
POND DIVERTER DIKE

Figure 5. Pond construction diagram.

TABLE 20. LIMESTONE SLURRY PROCESS

ACREAGE REQUIRED FOR WASTE SOLIDS DISPOSAL

Case	Years remaining life	Acres
Coal-Fired Power Unit		
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)		
200 MW E 3.5% sulfur	20	79
200 MW N 3.5% sulfur	30	142
500 MW E 3.5% sulfur	25	227
500 MW N 2.0% sulfur	30	155
500 MW N 3.5% sulfur	30	287
500 MW N 5.0% sulfur	30	424
1,000 MW E 3.5% sulfur	25	383
1,000 MW N 3.5% sulfur	30	480
Solids disposal by trucking		
500 MW N 3.5% sulfur	30	96
90% SO_2 removal; onsite solids disposal (ponding)		
500 MW N 3.5% sulfur	30	329
Oil-Fired Power Unit		
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)		
500 MW E 2.5% sulfur	25	110

GENERIC DOUBLE-ALKALI PROCESS

The double-alkali process included in this study (Figure 6) has been generalized from the several processes currently available in the United States. In this design, an ESP is used for removal of fly ash and a common plenum and booster fans are included downstream from the ESP and the power plant ID fans for distribution of the gas (Figure 7).

Flue gas is cooled and saturated in a presaturator with a recycle stream of scrubber effluent. In the absorber tower SO_2 is removed using a mixture of a regenerated sodium sulfite solution and recycle scrubber effluent (pH about 6.0). The outlet gas from the scrubber passes through a chevron-type entrainment separator with provisions for upstream wash with fresh makeup water. The cleaned flue gas is reheated to 175°F by indirect steam heat before entering the stack.

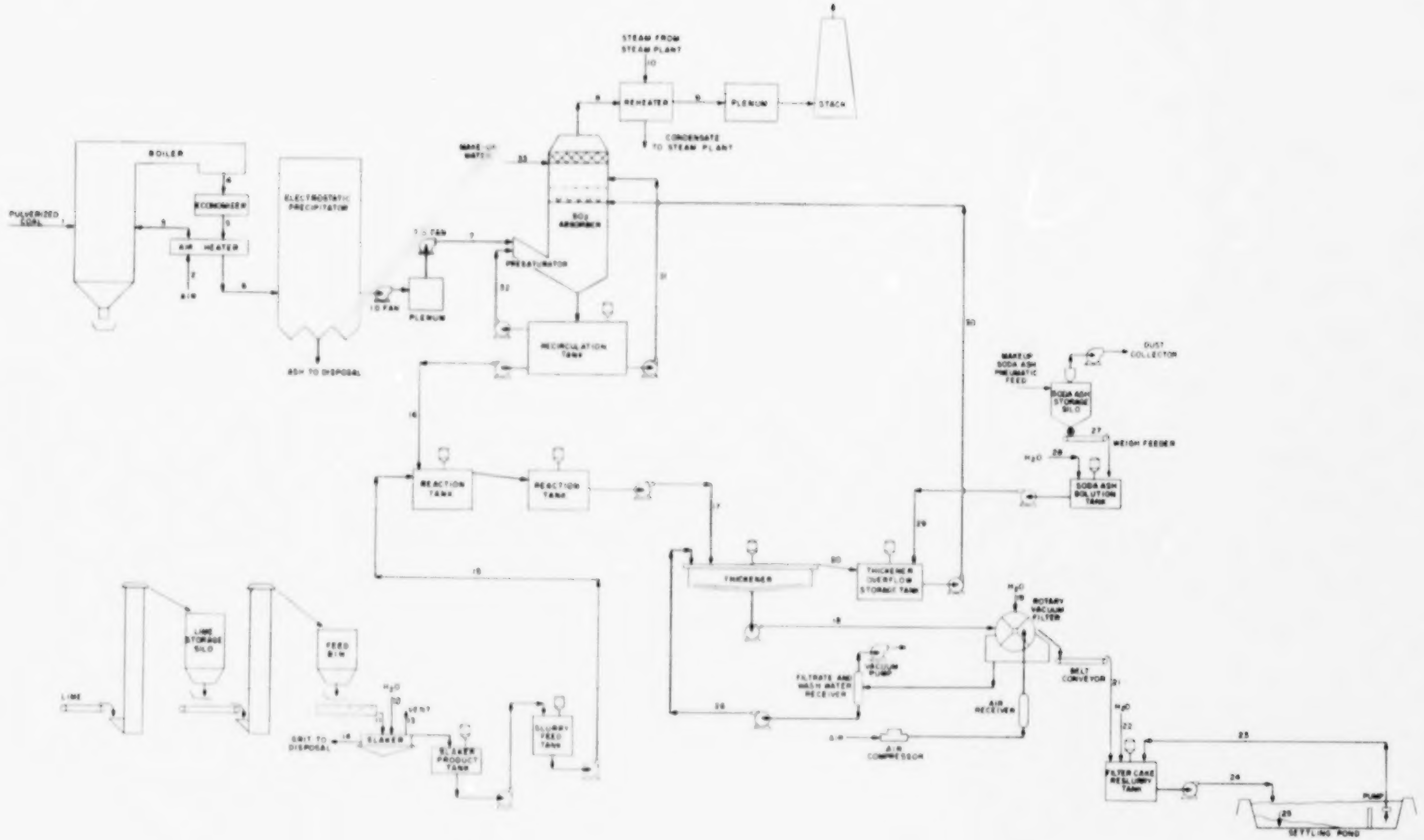
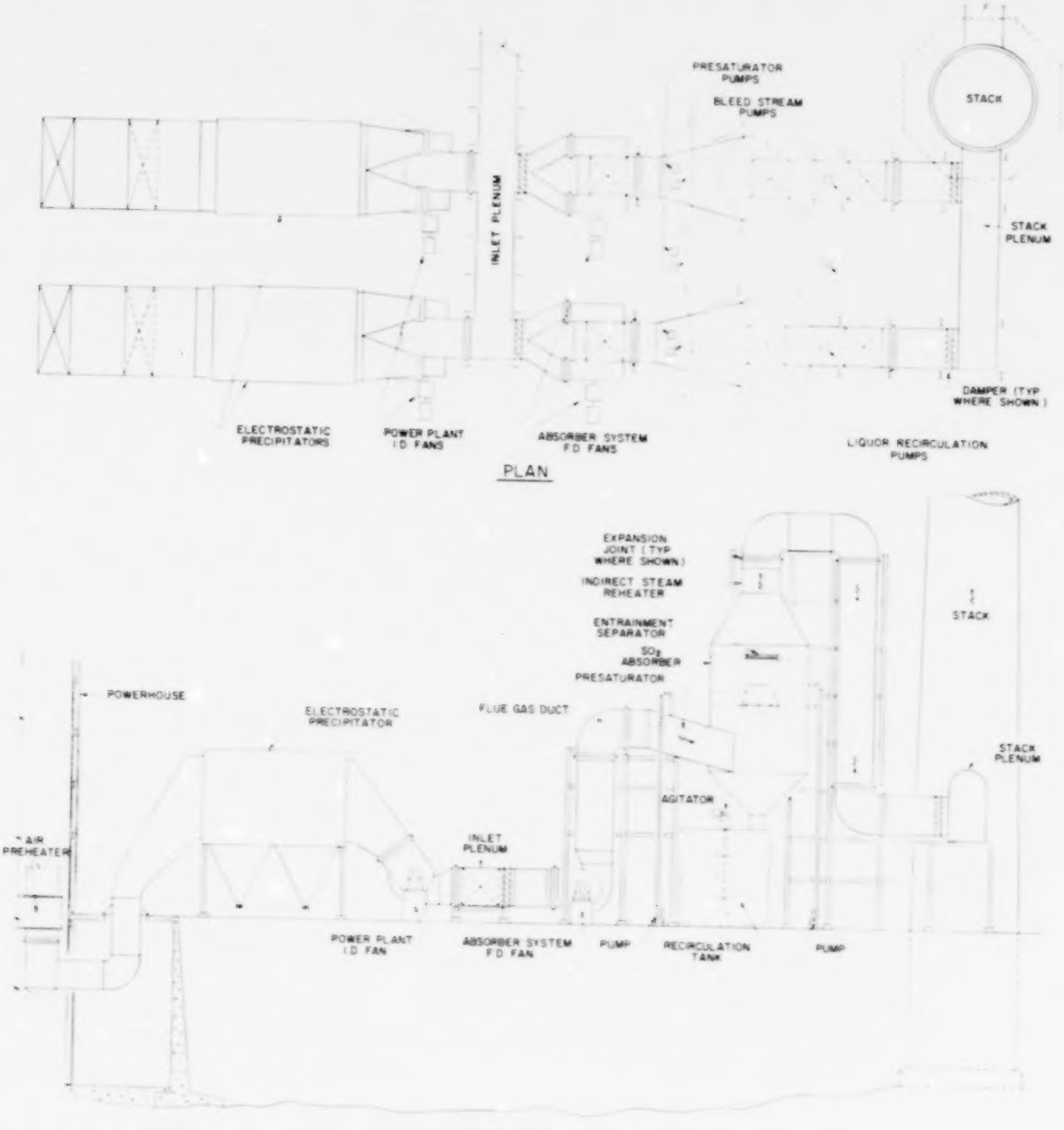

PULVERIZED COAL
BOILER
ECONOMIZER
AIR HEATER
AIR
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
ID FAN
PLENUM
PRESATURATOR
MAKE-UP WATER
SO2 ABSORBER
RECIRCULATION TANK
STEAM FROM STEAM PLANT
REHEATER
CONDENSATE TO STEAM PLANT
PLENUM
STACK
REACTION TANK
REACTION TANK
LIME
LIME STORAGE SILO
FEED BIN
H2O
VENT
GRIT TO DISPOSAL
SLAKER
SLAKER PRODUCT TANK
SLURRY FEED TANK
THICKENER
THICKENER OVERFLOW STORAGE TANK
MAKEUP SODA ASH PNEUMATIC FEED
SODA ASH STORAGE SILO
DUST COLLECTOR
WEIGH FEEDER
SODA ASH SOLUTION TANK
ROTARY VACUUM FILTER
VACUUM PUMP
FILTRATE AND WASH WATER RECEIVER
AIR RECEIVER
AIR COMPRESSOR
BELT CONVEYOR
FILTER CAKE RESLURRY TANK
PUMP
SETTLING POND

Figure 6. Generic double-alkali process. Base case flow diagram.


PRESATURATOR PUMPS
BLEED STREAM PUMPS
STACK
INLET PLENUM
STACK PLENUM
DAMPER (TYP WHERE SHOWN)
ELECTROSTATIC PRECIPITATORS
POWER PLANT I D FANS
ABSORBER SYSTEM F D FANS
LIQUOR RECIRCULATION PUMPS
EXPANSION JOINT (TYP WHERE SHOWN)
INDIRECT STEAM REHEATER
ENTRAINMENT SEPARATOR
SO2 ABSORBER
PRESATURATOR
STACK
POWERHOUSE
ELECTROSTATIC PRECIPITATOR
FLUE GAS DUCT
STACK PLENUM
AGITATOR
AIR PREHEATER
INLET PLENUM
POWER PLANT I D FAN
ABSORBER SYSTEM F D FAN
PUMP
RECIRCULATION TANK
PUMP

PLAN

ELEVATION

Figure 7. Generic double-alkali process. Perforated-tray scrubber system base case plan and elevation.

Incoming pebble lime, from an across-the-fence limestone calcination plant, is received in a silo with a 10-day capacity and conveyed to two 4-hour feed bins that supply the slakers (Figures 8 and 9). The lime is processed in two parallel slakers to a slurry concentration of 15% solids. A slurry feed tank with a residence time of 8 hours is provided for in-process storage.

Lime slurry is reacted with a bleedstream of absorber effluent in agitated tanks. The reaction product, predominately calcium sulfite, is pumped to a thickener where the slurry is concentrated to 25% solids. This stream is further dewatered using drum filters to produce a cake of about 55% solids. The filter is designed with two wash sections to minimize sodium loss. The filter cake is reslurried to 15% solids with supernate from the pond and fresh makeup water for pumping to disposal. The solids settle to a concentration of approximately 40% in the pond. A special case is evaluated in which the spent slurry, after thickening and filtering, is trucked to a disposal site located 1 mile from the scrubbing facilities.

Makeup soda ash is pneumatically conveyed from a rail hopper car to the storage silo and fed to an agitated tank where it is slurried in fresh makeup water. The slurry is added to the regenerated scrubber liquor at the thickener overflow storage tank.

The material balance for the base case double-alkali system is shown in Table 21 and a detailed equipment list by area for the system is presented in Table 22.

Major Process Areas

The generic double-alkali process has been divided into the following operating areas.

1. Materials handling. This area includes facilities for receiving pebble lime from an across-the-fence limestone calcination plant, lime storage silo, and in-process storage for supply to the slakers. Soda ash storage is also provided.

2. Feed preparation. Included in this area are two parallel slaking systems and the facilities for dissolving makeup soda ash in water before feeding to the absorption system.

3. Gas handling. Fan location and duct configuration is the same as the limestone slurry process.

4. SO_2 absorption. Four tray tower absorbers with presaturators, recirculation tanks, and pumps are included.

5. Stack gas reheat. Equipment in this area includes indirect steam reheaters and soot blowers for the coal variations. The oil-fired unit is designed with one direct oil-fired reheater per duct which discharges hot combustion gases directly into the duct.

6. Reaction. Reaction tanks with agitators and pumps are provided in this area.

7. Solids separation. Separation of calcium salts is accomplished by thickener and filters.

8. Solids disposal. Filter cake is reslurried in this area and purged to the disposal pond. A pond return pump is included.

Storage Capacity

Storage requirements for raw materials and allowances for in-process streams are listed below.

Raw materials:
  Lime storage silo - 10 days (from across-the-fence calcination plant)
  Soda ash storage silo - 4 months (purchased in bulk quantity by rail)

In-process storage:
  Lime feed bins - 4 hours each
  Slaker product tank - 5 minutes
  Slurry feed tank - 8 hours
  Soda ash solution tank - 8 hours
  Recirculation tanks - 10 minutes each (includes sufficient surge capacity for shutdown of scrubbers)
  Thickener - 4 hours
  Thickener overflow storage tank - 20 minutes
  Filter cake reslurry tank - 5 minutes

Solids Disposal

Waste solids in the generic double-alkali process are handled in the same manner as the limestone slurry process.

Pond Construction--

Pond designs are similar to the design for the limestone slurry process. Total pond depth for the base case is 18.9 feet and excavation depth is 3.1 feet. Pond areas for each case variation are listed in Table 23.

Trucking Alternative--

Transport of waste solids by truck to a disposal area is similar to the method used for the limestone process.

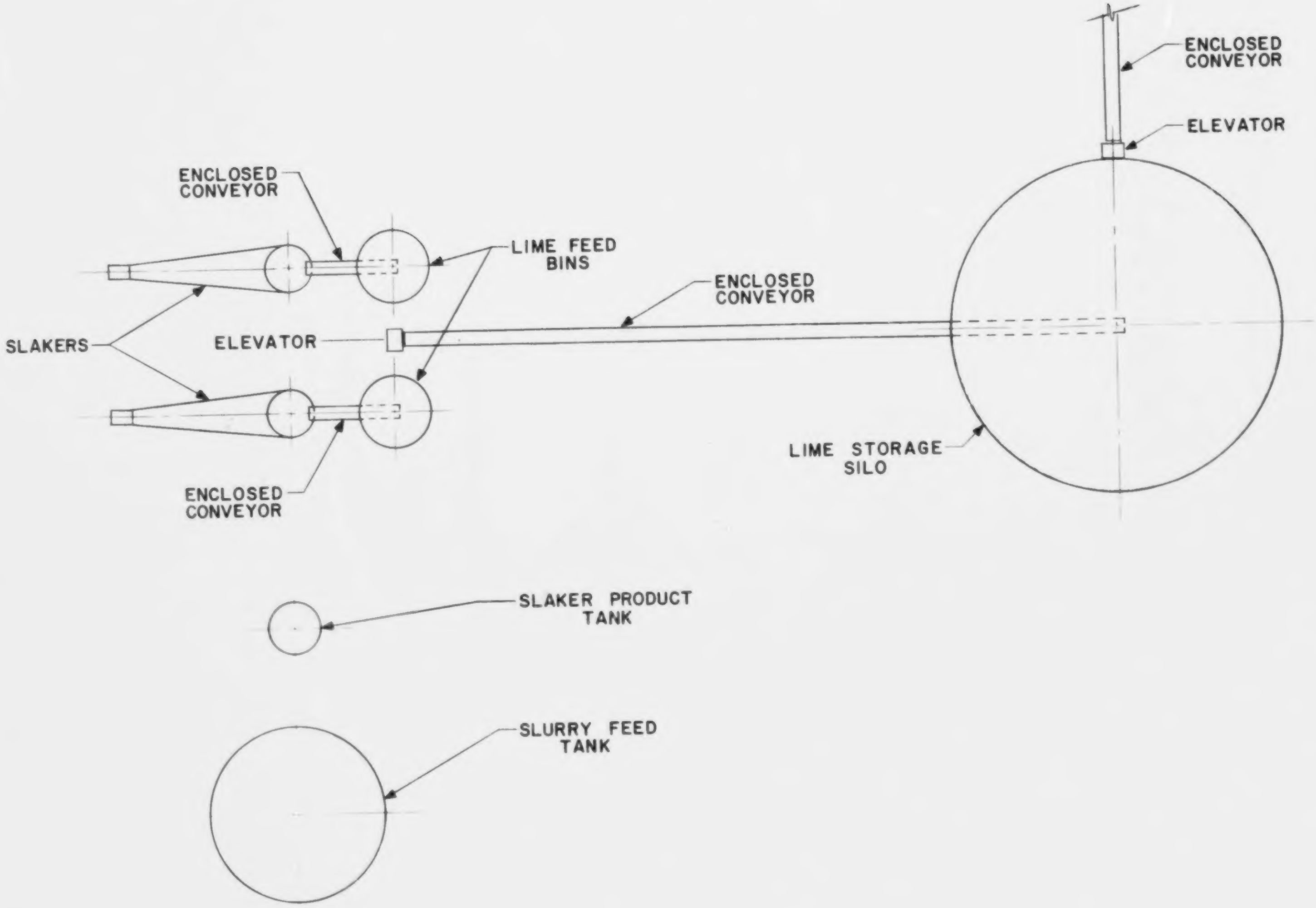

ENCLOSED CONVEYOR
ELEVATOR
ENCLOSED CONVEYOR
LIME FEED BINS
ENCLOSED CONVEYOR
SLAKERS
ELEVATOR
LIME STORAGE SILO
ENCLOSED CONVEYOR
SLAKER PRODUCT TANK
SLURRY FEED TANK

Figure 8. Generic double-alkali process. Base case materials handling and feed preparation system layout.

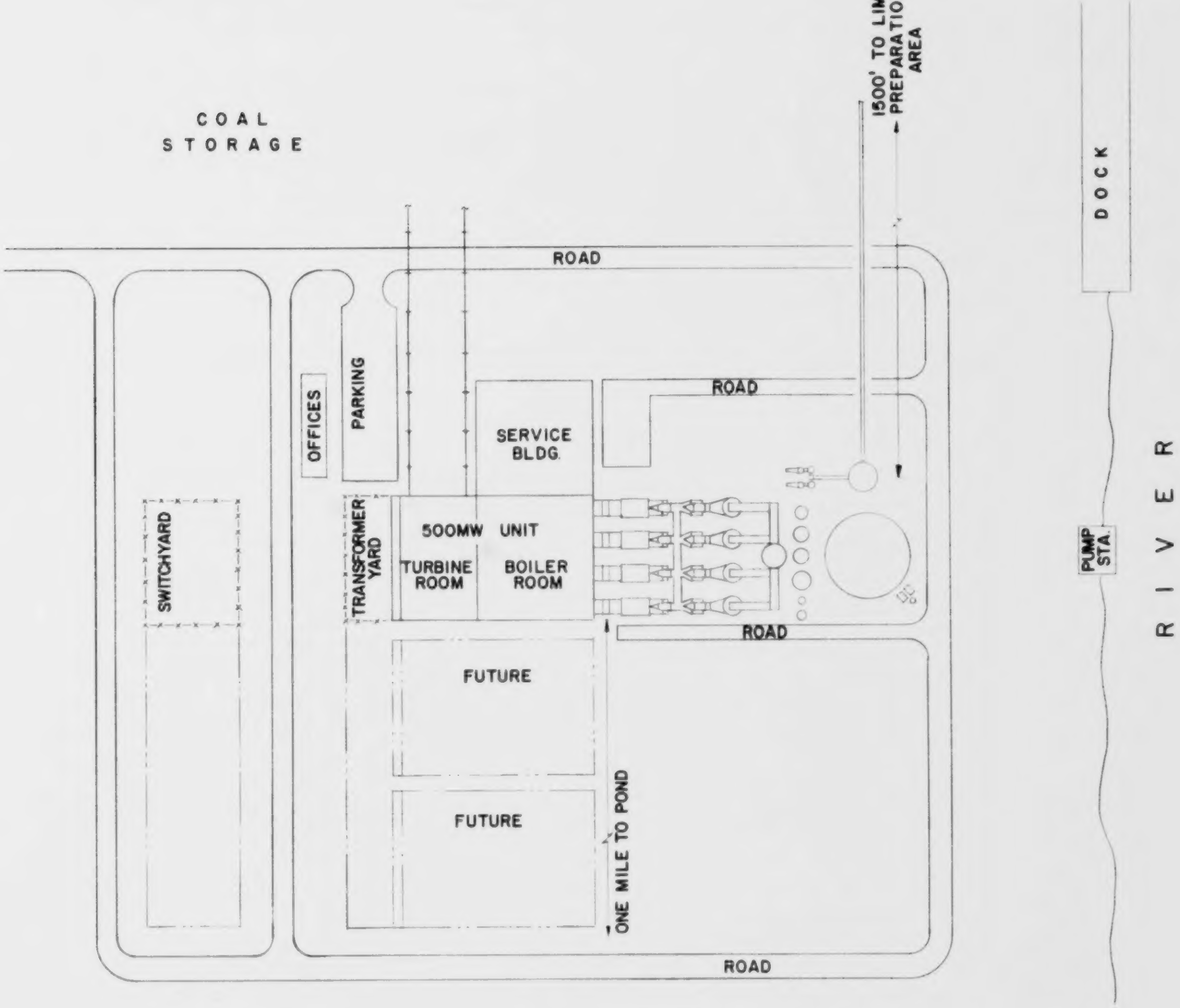

COAL STORAGE
1500' TO LIME PREPARATION AREA
DOCK
ROAD
OFFICES
PARKING
SERVICE BLDG.
ROAD
SWITCHYARD
TRANSFORMER YARD
500MW UNIT
TURBINE ROOM
BOILER ROOM
ROAD
FUTURE
FUTURE
ONE MILE TO POND
ROAD
PUMP STA.
RIVER

Figure 9. Generic double-alkali process. Base case overall plot plan.

TABLE 21. GENERIC DOUBLE-ALKALI PROCESS

MATERIAL BALANCE - BASE CASE

Stream No.		1	2	3	4	5
Description		Coal to boiler	Combustion air to air heater	Combustion air to boiler	Gas to economizer	Gas to air heater
1	Total stream, lb/hr	428,600	4,546,200	4,101,800	4,516,100	4,516,100
2	sft^3/min (60°F)		1,005,000	906,700	958,000	958,000
3	Temperature, $^\circ$F		80	535	890	705
4	Pressure, psig					
5	gpm					
6	Specific gravity					
7	pH					
8	Undissolved solids, %					
9						
10						

Stream No.		6	7	8	9	10
Description		Gas to electrostatic precipitator	Gas to presaturator	Gas to reheater	Gas to stack	Steam to reheater
1	Total stream, lb/hr	4,960,400	4,905,800	5,094,000	5,094,000	92,810
2	sft^3/min (60°F)	1,056,000	1,056,000	1,125,000	1,126,700	
3	Temperature, $^\circ$F	300	300	127	175	470
4	Pressure, psig					500
5	gpm					
6	Specific gravity					
7	pH					
8	Undissolved solids, %					
9						
10						

Stream No.		11	12	13	14	15
Description		Lime to slaker	Water to slaker	Vent from slaker	Grit to disposal	Lime slurry to reaction tank
1	Total stream, lb/hr	18,170	135,150	1,056	182	152,080
2	sft^3/min (60°F)					
3	Temperature, $^\circ$F					
4	Pressure, psig					
5	gpm		270	2		279
6	Specific gravity					1.09
7	pH					
8	Undissolved solids, %					15
9						
10						

Stream No.		16	17	18	19	20
Description		Bleedstream to reaction tank	Slurry to thickener	Thickener underflow to filter	Filter wash water	Thickener overflow to storage tank
1	Total stream, lb/hr	1,898,900	2,051,000	167,800	59,700	2,034,400
2	sft^3/min (60°F)					
3	Temperature, $^\circ$F					
4	Pressure, psig					
5	gpm	3,547	3,726	271	120	3,800
6	Specific gravity	1.07	1.1	1.24		1.07
7	pH	6.0	11.0			
8	Undissolved solids, %		2	25		
9						
10						

(continued)

TABLE 21 (continued)

	Stream No.	21	22	23	24	25
	Description	Filter cake to reslurry tank	Water to reslurry tank	Recycle pond water	Slurry to pond	Settled sludge
1	Total stream, lb/hr	76,270	28,600	174,780	279,650	104,870
2	sft^3/min (60^{o}F)					
3	Temperature, ^{o}F					
4	Pressure, psig					
5	gpm		57	349	508	161
6	Specific gravity				1.1	1.3
7	pH					
8	Undissolved solids, %	55			15	40
9						
10						

	Stream No.	26	27	28	29	30
	Description	Filtrate to thickener	Soda ash to solution tank	Water to solution tank	Makeup soda ash stream	Scrubbing liquor to absorber
1	Total stream, lb/hr	151,230	1,730	9,800	11,530	2,045,900
2	sft^3/min (60^{o}F)					
3	Temperature, ^{o}F					
4	Pressure, psig					
5	gpm	283		20	20	3,821
6	Specific gravity	1.07			1.14	1.07
7	pH					
8	Undissolved solids, %					
9						
10						

	Stream No.	31	32	33		
	Description	Recycle liquor to absorber	Recycle liquor to presaturator	Makeup water to absorber		
1	Total stream, lb/hr	2,727,500	2,727,500	41,100		
2	sft^3/min (60^{o}F)					
3	Temperature, ^{o}F					
4	Pressure, psig					
5	gpm	5,094	5,094	82		
6	Specific gravity	1.07	1.07			
7	pH	5.8				
8	Undissolved solids, %					
9						
10						

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

TABLE 22. GENERIC DOUBLE-ALKALI PROCESS

BASE CASE EQUIPMENT LIST DESCRIPTION AND COST

Area 1--Materials Handling

	Item	No.	Description	Total material cost, 1979 $
1.	Conveyor, lime storage (enclosed)	1	Belt, 24 in. wide x 1,500 ft long, 30 hp, 100 tons/hr, 150 ft/min	169,900
2.	Elevator, lime storage	1	Continuous, bucket 16 in. x 8 in. x 11-3/4 in., 75 hp, 120 ft lift, 100 tons/hr, 160 ft/min	102,900
3.	Silo, lime storage	1	46 ft dia x 69 ft high, 109,000 ft^3, cone bottom, 3/8 in. carbon steel	75,900
4.	Feeder, reclaim	1	Vibrating pan, 3-1/2 hp, 40 tons/hr	12,200
5.	Conveyor, live lime feed	1	Belt, 18 in. wide x 100 ft long, 2 hp, 40 tons/hr, 100 ft/min	9,300
6.	Elevator, live lime feed	1	Continuous, bucket 11 in. x 6 in. x 8-3/4 in., 50 hp, 50 ft lift, 40 tons/hr, 160 ft/min, with diverter gate	56,000
7.	Bin, lime feed	2	10 ft dia x 15 ft high, 1,180 ft^3, w/cover, carbon steel	5,400
8.	Conveyor, soda ash storage	1	Pneumatic, vacuum, 40 hp	65,000
9.	Silo, soda ash storage	1	15 ft dia x 30 ft high, 5,850 ft^3, cone bottom, carbon steel	9,200
	Vibrators	4		6,100
10.	Dust collecting system	1	Bag filter, polypropylene bag, 8,800 aft^3/min, automatic shaker system	21,400
	Subtotal			533,300

(continued)

TABLE 22 (continued)

Area 2--Feed Preparation

Item	No.	Description	Total material cost, 1979 $
1. Feeder, lime bin discharge	2	Vibrating, 3-1/2 hp, carbon steel	9,200
2. Feeder, slaker	2	Screw, 12 in. dia x 12 ft long, 1 hp, 5 tons/hr	12,000
3. Slaker	2	6 ft wide x 28 ft long, 10 hp slaker, 2 hp classifier, 5 tons/hr	108,000
4. Tank, slaker product	2	7 ft dia x 6 ft high, 1,730 gal, open top, four 7 in. baffles, agitator supports, carbon steel	2,100
Lining		1/4 in. neoprene lining	1,700
5. Agitator, slaker product tank	2	30 in. dia, 5 hp, neoprene coated	17,500
6. Pump, slaker product tank	3	Centrifugal, 140 gpm, 100 ft head, 7-1/2 hp, carbon steel, neoprene lined	8,700
7. Tank, slurry feed	1	24 ft dia x 36 ft high, 122,000 gal, open top, four 24 in. baffles, agitator supports, carbon steel	18,500
Lining		1/4 in. neoprene lining	17,500
8. Agitator, slurry feed tank	1	2 turbines, 96 in. dia, 50 hp, neoprene coated	46,600
9. Pump, slurry feed tank	2	Centrifugal, 279 gpm, 100 ft head, 15 hp, carbon steel, neoprene lined	6,700
10. Feeder, soda ash silo discharge	1	Rotary air lock, carbon steel	2,500
11. Feeder, soda ash solution tank	1	Weigh	5,400
12. Tank, soda ash solution	1	12 ft dia x 14 ft high, 11,850 gal, open top, four 12 in. baffles, agitator supports, carbon steel	3,900
Lining		1/4 in. neoprene lining	3,500

(continued)

TABLE 22 (continued)

Item	No.	Description	Total material cost, 1979 $
13. Agitator, soda ash solution tank	1	48 in. dia, 15 hp, neoprene coated	19,500
14. Pump, soda ash solution tank	2	20 gpm, 60 ft head, 1 hp, carbon steel, neoprene lined	4,700
Subtotal			288,000

Area 3--Gas Handling

Item	No.	Description	Total material cost, 1979 $
1. Fans	4	Forced draft, 8 in. static head, 700 rpm, 850 hp, fluid drive, double width, double inlet	752,000
Subtotal			752,000

Area 4--SO_2 Absorption

Item	No.	Description	Total material cost, 1979 $
1. SO_2 absorber	4	Tray tower, 31 ft dia x 40 ft high, 3/8 in. carbon steel, flake-lined; 1-316 SS sieve tray, 316 SS nozzles, polypropylene chevron vane entrainment separator	3,316,800
2. Tank, recirculation	4	28 ft dia x 30 ft high, 137,350 gal, open top, four 28 in. baffles, agitator supports, carbon steel	76,000
Lining		1/4 in. neoprene lining	71,200
3. Agitator, recirculation tank	4	108 in. dia, 25 hp, neoprene coated	113,800
4. Pump, presaturator	6	Centrifugal, 1,274 gpm, 105 ft head, 75 hp, carbon steel, neoprene lined	58,000
5. Pump, liquor recirculation	6	Centrifugal, 1,274 gpm, 105 ft head, 75 hp, carbon steel, neoprene lined	58,000

(continued)

TABLE 22 (continued)

	Item	No.	Description	Total material cost, 1979 $
6.	Pump, bleed to reaction	6	Centrifugal, 887 gpm, 100 ft head, 60 hp, carbon steel, neoprene lined	40,200
7.	Pump, makeup water	2	Centrifugal, 1,000 gpm, 150 ft head, 60 hp, carbon steel	12,000
8.	Soot blowers	40	Air, retractable	260,000
	Subtotal			4,006,000

Area 5--Reheat

	Item	No.	Description	Total material cost, 1979 $
1.	Reheater	4	Steam, tube type, 3,600 ft^2, one-half tubes made of Inconel 625, and one-half made of Cor-Ten	856,000
2.	Soot blowers	20	Air, retractable	130,000
	Subtotal			986,000

Area 6--Reaction Tanks

	Item	No.	Description	Total material cost, 1979 $
1.	Tank, reaction	2	26 ft dia x 15 ft high, 59,570 gal, open top, four 26 in. baffles, agitator supports, carbon steel	20,600
	Lining		1/4 in. neoprene lining	18,800
2.	Agitator, reaction tank	2	100 in. dia, 25 hp, neoprene coated	56,600
3.	Pump, reaction tank	2	Centrifugal, 3,726 gpm, 50 ft head, 100 hp, carbon steel, neoprene lined	31,200
	Subtotal			127,200

(continued)

TABLE 22 (continued)

Area 7--Solids Separation

	Item	No.	Description	Total material cost, 1979 $
1.	Thickener	1	Stainless steel tank, 140 ft dia x 8 ft high; concrete basin, 4 ft high	112,900
	Rake motor and mechanism		7-1/2 hp	422,000
2.	Pump, underflow slurry	2	Centrifugal, 271 gpm, 100 ft head, 20 hp, carbon steel, neoprene lined	9,300
3.	Tank, thickener overflow storage	1	33 ft dia x 15 ft high, 96,000 gal, open top, four 33 in. baffles, agitator supports, carbon steel	14,000
	Lining		1/4 in. neoprene lining	12,800
4.	Agitator, thickener overflow storage tank	1	132 in. dia, 25 hp, neoprene coated	28,500
5.	Pump, scrubbing liquor return	6	Centrifugal, 955 gpm, 125 ft head, 60 hp, carbon steel, neoprene lined	41,600
6.	Filter	2	Rotary vacuum, 12 ft dia x 14 ft face, 20 total hp	251,300
7.	Pump, filter wash water	2	240 gpm, 80 ft head, 15 hp, carbon steel	4,800
8.	Conveyor, filter cake	1	Belt, 18 in. wide x 100 ft long, 5 hp, 40 tons/hr, 100 ft/min	9,800
	Subtotal			907,000

(continued)

TABLE 22 (continued)

Area 8--Solids Disposal

	Item	No.	Description	Total material cost, 1979 $
1.	Tank, filter cake reslurry	1	7 ft dia x 10 ft high, 2,700 gal, open top, four 7 in. baffles, agitator supports, carbon steel	1,600
	Lining		1/4 in. neoprene lining	1,400
2.	Agitator, filter cake reslurry tank	1	30 in. dia, 7-1/2 hp, neoprene coated	11,700
3.	Pump, pond feed	2	Centrifugal, 508 gpm, 110 ft head, 50 hp, carbon steel, neoprene lined	12,400
4.	Pump, pond return	2	Centrifugal, 349 gpm, 110 ft head, 25 hp, carbon steel, neoprene lining	9,900
	Subtotal			37,000

TABLE 23. GENERIC DOUBLE-ALKALI PROCESS

ACREAGE REQUIRED FOR WASTE SOLIDS DISPOSAL

Case	Years remaining life	Acres
Coal-Fired Power Unit		
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)		
200 MW E 3.5% sulfur	20	64
200 MW N 3.5% sulfur	30	116
500 MW E 3.5% sulfur	25	187
500 MW N 2.0% sulfur	30	127
500 MW N 3.5% sulfur	30	233
500 MW N 5.0% sulfur	30	329
1,000 MW E 3.5% sulfur	25	315
1,000 MW N 3.5% sulfur	30	393
Solids disposal by trucking		
500 MW N 3.5% sulfur	30	87
90% SO_2 removal; onsite solids disposal (ponding)		
500 MW N 3.5% sulfur	30	260
Oil-Fired Power Unit		
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)		
500 MW E 2.5% sulfur	25	97

CITRATE PROCESS

The citrate process design developed for this study (Figure 10) is adapted from a U.S. Bureau of Mines process and represents the state of technology in 1977. The demonstration program for the Bureau of Mines citrate process has been in active development during the time for preparation of this report. Certain features of the demonstration design which are significantly different from the process design represented here have been identified under Major Process Areas.

The scheme evaluated assumes fly ash removal by ESP. Power plant ID fans feeding a common plenum and booster FD fans are included in the design (Figure 11). Flue gas is cooled and saturated in a presaturator with recycle liquor from the bottom of the scrubber. SO_2 is removed from the flue gas by countercurrent scrubbing in a packed tower using a regenerated solution containing sodium citrate as a buffer. A purge stream to control chlorides is pumped from the bottom of the absorber through an SO_2 stripper to a neutralization tank where it is reacted with lime before being pumped to the ash disposal pond. Stripped SO_2 is returned to the absorption tower at the presaturator. Cleaned flue gas is passed through a chevron-type entrainment separator with provisions for upstream wash with fresh makeup water and reheated to 175°F by indirect steam heat before entering the stack.

Elemental sulfur is precipitated from the SO_2-laden sorbent in reduction tanks by countercurrent contact with H_2S gas containing 80% to 97% H_2S. The sulfur is separated by air flotation, then melted and settled from the slurry liquor in a decanter operating at a pressure of about 35 psig (Figure 12). Storage is provided for the molten sulfur before marketing.

Hydrogen from natural gas or other sources and a portion of the molten product sulfur from the decanter are feedstocks for H_2S generation. The system guards against H_2S escape in the reduction step by returning unreacted H_2S to the boiler for incineration and by neutralizing dissolved H_2S downstream from the reducing tanks with a small stream of SO_2-rich liquor from the absorber (5% of the absorber effluent).

About 2% of the absorbed SO_2 is oxidized in the system to sodium sulfate. This sulfate, along with the sulfate formed from absorption of SO_3 in the flue gas and thiosulfate decomposition during the sulfur melting step, is removed from the recirculated sorbent by crystallization as Glauber's salt ($Na_2SO_4 \cdot 10H_2O$), which is disposed of in the fly ash pond. Liquor from the flotation tank is filtered to remove remaining sulfur particles before cooling and crystallizing. The sulfate crystals are separated by centrifuge and the liquor is returned to the system. Sodium and citrate losses are replaced by adding a mixture of sodium hydroxide or sodium carbonate and citric acid to the recycling sorbent.

The general layout (plot plan) for the citrate system is shown in Figure 13. A material balance for the base case citrate scrubbing process is shown in Table 24 and a detailed equipment list by area for the system is presented in Table 25.

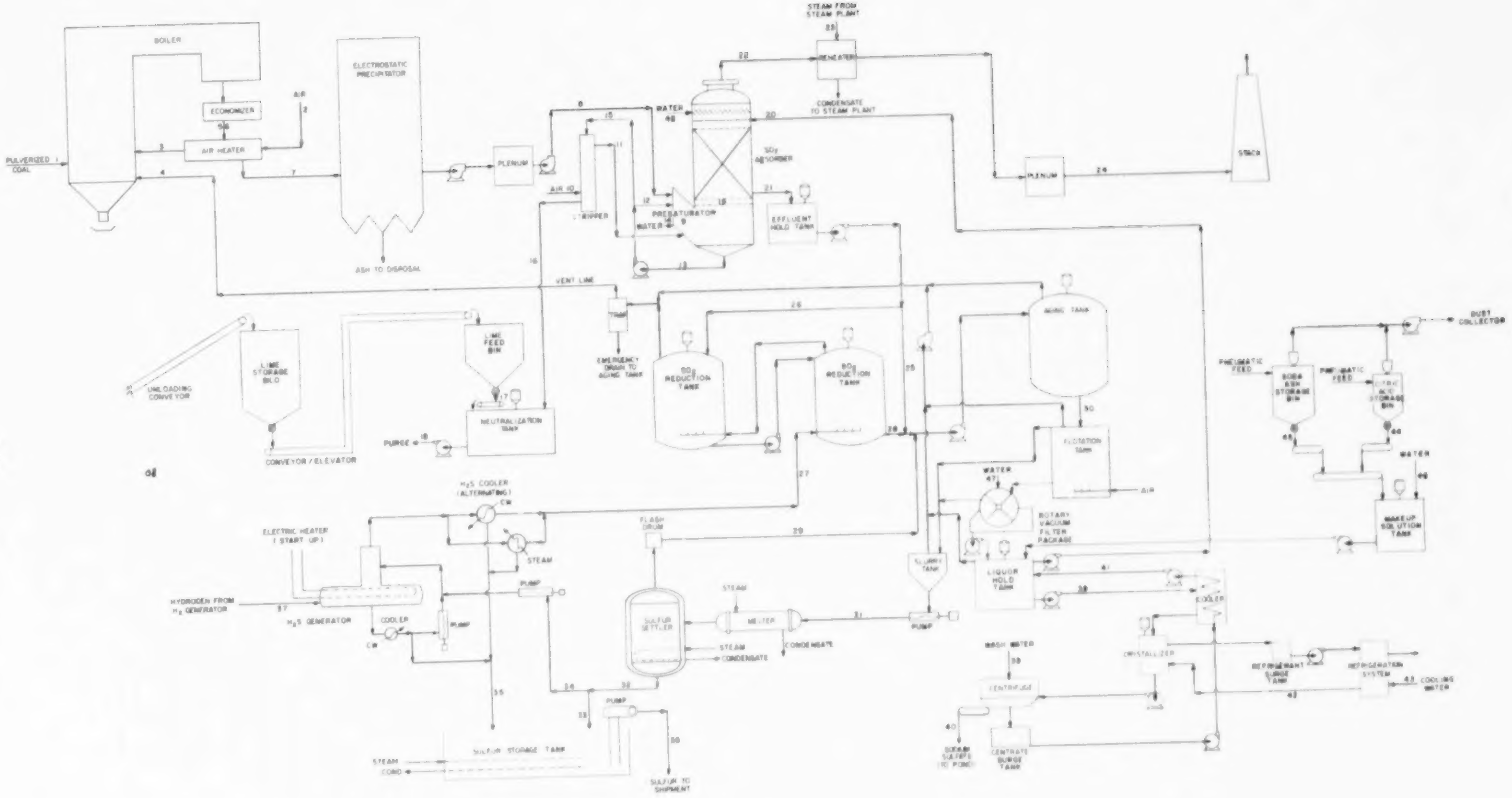
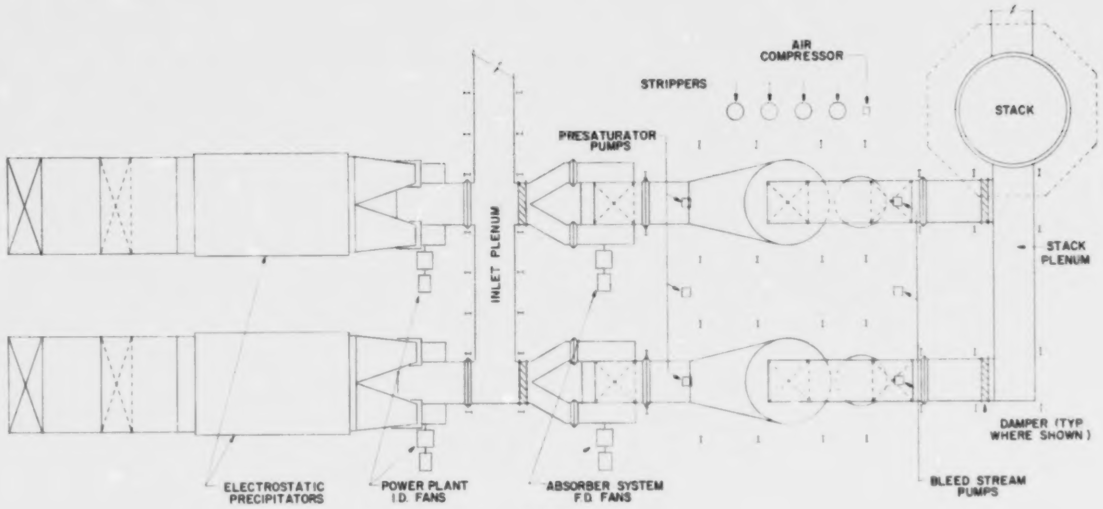
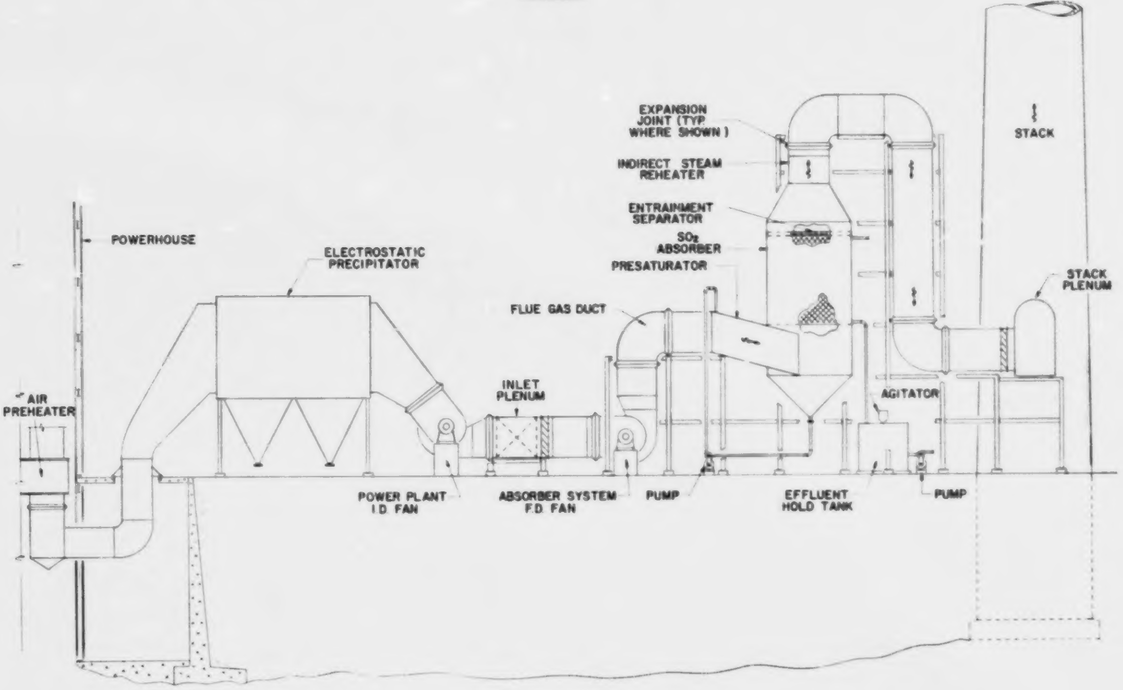

BOILER
PULVERIZED COAL
1
ECONOMIZER
5,6
AIR HEATER
AIR
2
3
4
7
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
PLENUM
8
15
11
AIR 10
STRIPPER
12
PRESATURATOR
WATER
14
9
13
16
WATER
48
SO2 ABSORBER
19
20
21
22
STEAM FROM STEAM PLANT
23
REHEATER
CONDENSATE TO STEAM PLANT
PLENUM
24
STACK
EFFLUENT HOLD TANK
VENT LINE
TRAP
EMERGENCY DRAIN TO AGING TANK
UNLOADING CONVEYOR
LIME STORAGE SILO
CONVEYOR / ELEVATOR
LIME FEED BIN
17
NEUTRALIZATION TANK
PURGE
18
26
SO2 REDUCTION TANK
SO2 REDUCTION TANK
25
27
28
29
AGING TANK
30
FLOTATION TANK
AIR
WATER
47
ROTARY VACUUM FILTER PACKAGE
SLURRY TANK
LIQUOR HOLD TANK
41
39
COOLER
PUMP
31
WASH WATER
38
CENTRIFUGE
40
SODIUM SULFATE TO POND
CENTRATE SURGE TANK
CRYSTALLIZER
REFRIGERANT SURGE TANK
REFRIGERATION SYSTEM
42
43
COOLING WATER
PNEUMATIC FEED
SODA ASH STORAGE BIN
45
PNEUMATIC FEED
CITRIC ACID STORAGE BIN
44
DUST COLLECTOR
WATER
46
MAKEUP SOLUTION TANK
H2S COOLER (ALTERNATING)
CW
STEAM
ELECTRIC HEATER (START UP)
HYDROGEN FROM H2 GENERATOR
37
H2S GENERATOR
COOLER
CW
PUMP
PUMP
35
FLASH DRUM
SULFUR SETTLER
STEAM
MELTER
STEAM
CONDENSATE
CONDENSATE
34
32
33
PUMP
36
SULFUR TO SHIPMENT
SULFUR STORAGE TANK
STEAM
COND

Figure 10. Citrate process. Base case flow diagram.


AIR COMPRESSOR
STRIPPERS
STACK
PRESATURATOR PUMPS
INLET PLENUM
STACK PLENUM
DAMPER (TYP WHERE SHOWN)
ELECTROSTATIC PRECIPITATORS
POWER PLANT I.D. FANS
ABSORBER SYSTEM F.D. FANS
BLEED STREAM PUMPS

PLAN


STACK
EXPANSION JOINT (TYP WHERE SHOWN)
INDIRECT STEAM REHEATER
ENTRAINMENT SEPARATOR
SO_2 ABSORBER
PRESATURATOR
POWERHOUSE
ELECTROSTATIC PRECIPITATOR
STACK PLENUM
FLUE GAS DUCT
INLET PLENUM
AGITATOR
AIR PREHEATER
POWER PLANT I.D. FAN
ABSORBER SYSTEM F.D. FAN
PUMP
EFFLUENT HOLD TANK
PUMP

ELEVATION

Figure 11. Citrate process. Packed-tower scrubber system base case plan and elevation.

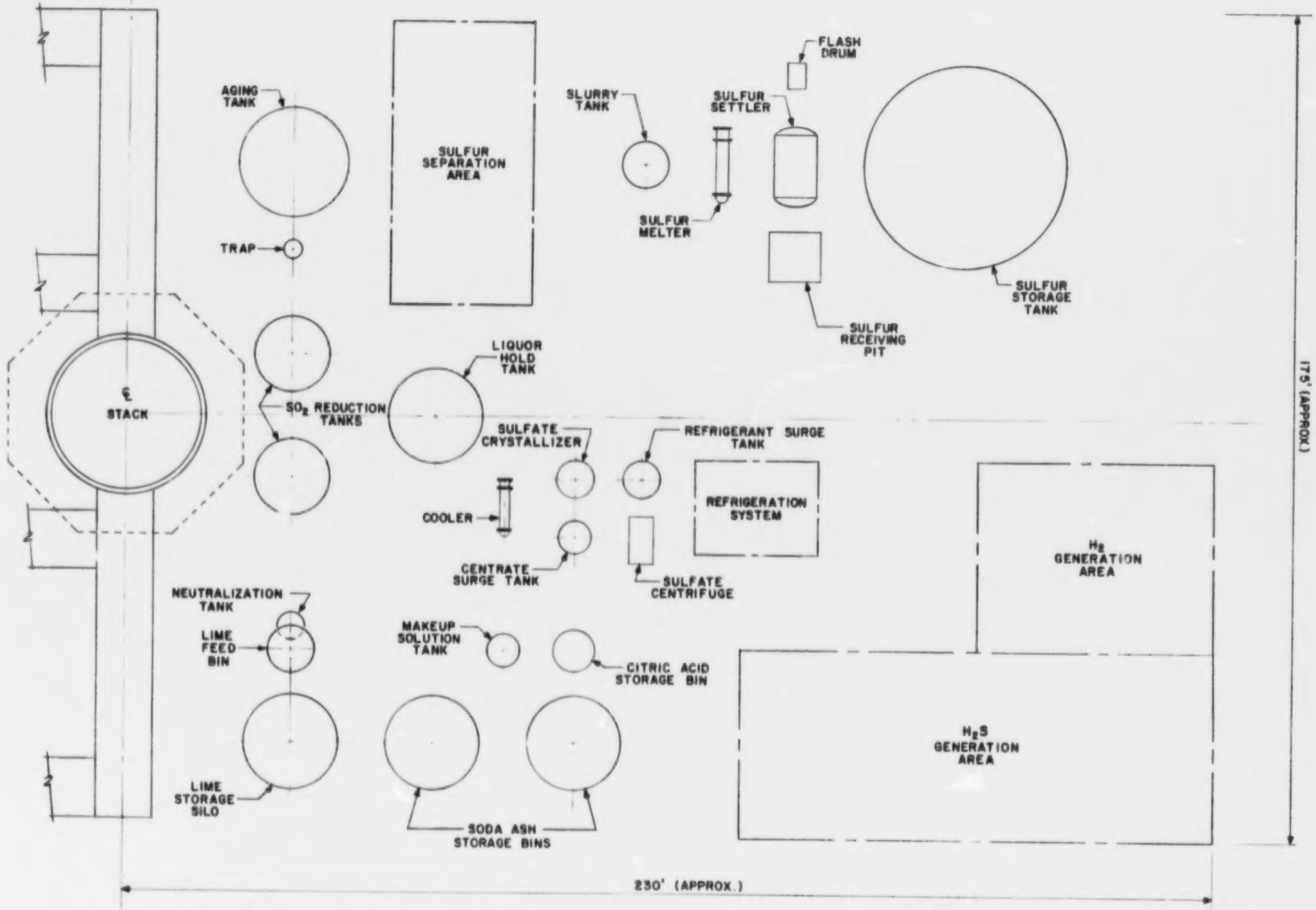

STACK
AGING TANK
TRAP
SO$_2$ REDUCTION TANKS
NEUTRALIZATION TANK
LIME FEED BIN
LIME STORAGE SILO
SULFUR SEPARATION AREA
LIQUOR HOLD TANK
COOLER
MAKEUP SOLUTION TANK
SODA ASH STORAGE BINS
SLURRY TANK
SULFUR MELTER
SULFUR SETTLER
FLASH DRUM
SULFUR RECEIVING PIT
SULFUR STORAGE TANK
SULFATE CRYSTALLIZER
CENTRATE SURGE TANK
REFRIGERANT SURGE TANK
SULFATE CENTRIFUGE
REFRIGERATION SYSTEM
CITRIC ACID STORAGE BIN
H$_2$ GENERATION AREA
H$_2$S GENERATION AREA
175' (APPROX.)
230' (APPROX.)

Figure 12. Citrate process. Base case sulfur processing area layout.

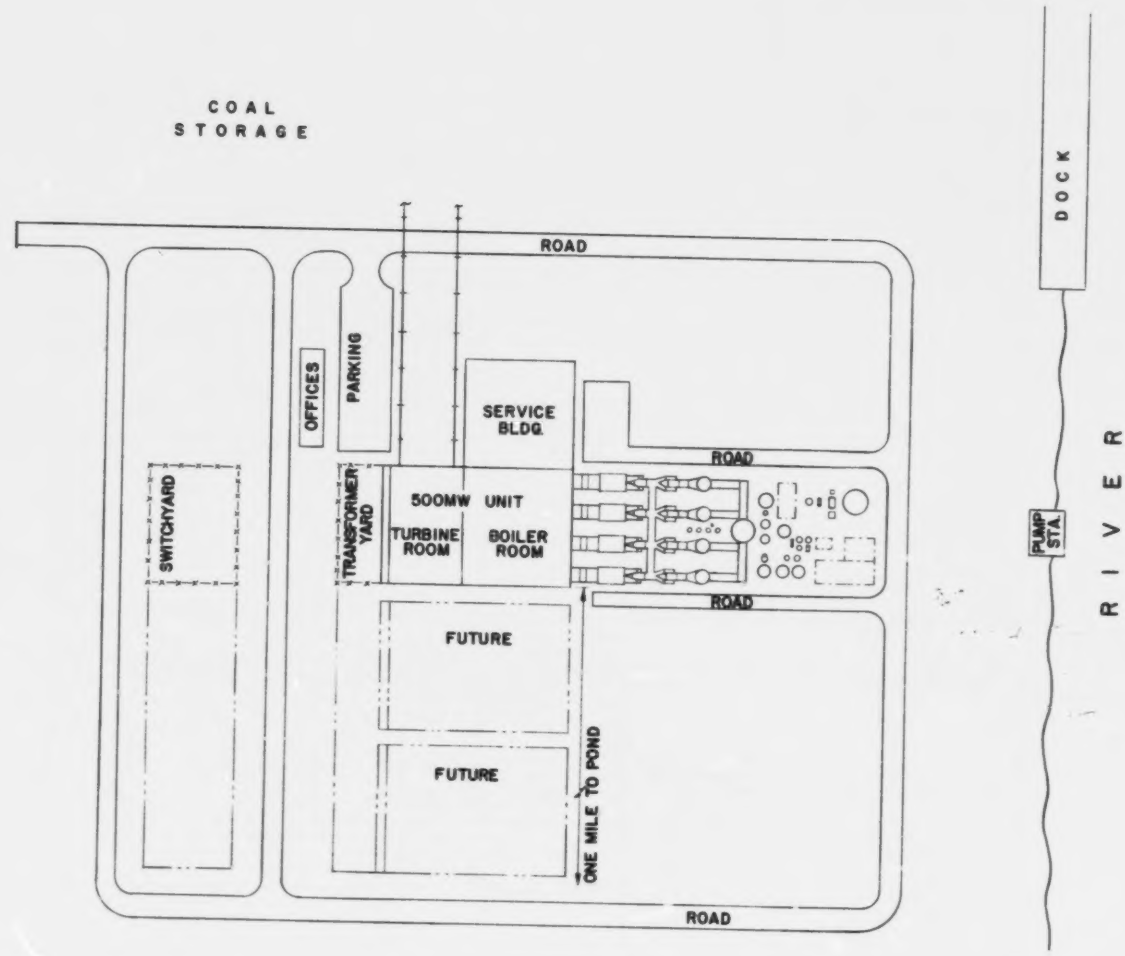

COAL STORAGE
DOCK
ROAD
OFFICES
PARKING
SERVICE BLDG.
ROAD
SWITCHYARD
TRANSFORMER YARD
500MW UNIT
TURBINE ROOM
BOILER ROOM
PUMP STA.
RIVER
ROAD
FUTURE
FUTURE
ONE MILE TO POND
ROAD

Figure 13. Citrate process. Base case overall plot plan.

TABLE 24. CITRATE PROCESS

MATERIAL BALANCE - BASE CASE

Stream No.		1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Combustion air to boiler	Vented H_2S gas to boiler	Coal flue gas to air heater
1	Total stream, lb/hr	428,600	4,546,200	4,101,800	660	4,515,000
2						
3						
4	sft^3/min (60°F)		1,005,000	906,700	190	957,800
5	Temperature, °F		80	535	128	705
6	Pressure, psig					
7	gpm					
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

Stream No.		6	7	8	9	10
	Description	H_2S flue gas to air heater	Gas to electrostatic precipitator	Gas to presaturator	Cooled gas to absorber base	Air to stripper
1	Total stream, lb/hr	1,750	4,961,100	4,906,500	5,087,000	4,200
2						
3						
4	sft^3/min (60°F)	300	1,056,300	1,056,300	1,102,400	930
5	Temperature, °F	705	300	300	128	
6	Pressure, psig					10
7	gpm					
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

Stream No.		11	12	13	14	15
	Description	Recycle gas to presaturator	Recycle liquor to presaturator	Liquor from presaturator	Makeup water to presaturator	Liquor to stripper
1	Total stream, lb/hr	4,770	2,614,100	2,640,500	181,700	26,410
2						
3						
4	sft^3/min (60°F)	1,060				
5	Temperature, °F	120				
6	Pressure, psig					
7	gpm		4,997	5,048	363	50
8	Specific gravity		1.04			
9	pH					
10	Undissolved solids, %					

Stream No.		16	17	18	19	20
	Description	Liquor to neutralization	Lime to neutralization	Slurry to pond	Flue gas to absorber	Scrubbing liquor to absorber
1	Total stream, lb/hr	25,840	655	26,500	5,091,500	3,500,800
2						
3						
4	sft^3/min (60°F)				1,121,000	
5	Temperature, °F				128	
6	Pressure, psig					
7	gpm	49		48		6,360
8	Specific gravity			1.1		1.1
9	pH					4.5
10	Undissolved solids, %			2		

(continued)

TABLE 24 (continued)

	Stream No.	21	22	23	24	25
	Description	Absorber effluent to hold tank	Gas to reheater	Steam to reheater	Gas to stack	Bypass liquor
1	Total stream, lb/hr	3,545,000	5,097,200	92,870	5,097,200	177,300
2						
3						
4	sft^3/min (60°F)		1,126,500		1,128,300	
5	Temperature, °F		127	470	175	
6	Pressure, psig			500		
7	gpm	6,440				322
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

	Stream No.	26	27	28	29	30
	Description	Liquor to SO_2 reduction	H_2S gas to SO_2 reduction	Slurry from SO_2 reduction	Return from sulfur settler	Slurry to flotation tank
1	Total stream, lb/hr	3,368,800	22,115	3,390,300	41,760	3,609,300
2						
3						
4	sft^3/min (60°F)		3,990			
5	Temperature, °F		130			
6	Pressure, psig					
7	gpm	6,120		6,159		6,558
8	Specific gravity					
9	pH					
10	Undissolved solids, %			0.9		

	Stream No.	31	32	33	34	35
	Description	Slurry to melter	Sulfur from melter	Sulfur to storage	Sulfur to H_2S generators	Sulfur from H_2S generators
1	Total stream, lb/hr	72,200	30,440	6,090	24,355	3,650
2						
3						
4	sft^3/min (60°F)					
5	Temperature, °F		307			
6	Pressure, psig		35			
7	gpm					
8	Specific gravity		1.78			
9	pH					
10	Undissolved solids, %					

	Stream No.	36	37	38	39	40
	Description	Sulfur to shipment	Hydrogen to H_2S generator	Liquor to cooler	Centrifuge wash water	Glauber salts to disposal
1	Total stream, lb/hr	9,735	1,350	35,450	600	2,990
2						
3						
4	sft^3/min (60°F)		4,150			
5	Temperature, °F					
6	Pressure, psig					
7	gpm			65	1	
8	Specific gravity					
9	pH					
10	Undissolved solids, %					80

(continued)

TABLE 24 (continued)

	Stream No.	41	42	43	44	45
	Description	Liquor recycle to hold tank	Refrigerant to crystallizer	Cooling H_2O to refrigeration	Citric acid to makeup solution tank	Soda ash to makeup solution tank
1	Total stream, lb/hr	33,060	221,520	123,420	75	855
2						
3						
4	sft^3/min (60°F)					
5	Temperature, °F		38			
6	Pressure, psig					
7	gpm	60	414	247		
8	Specific gravity		1.07			
9	pH					
10	Undissolved solids, %					

	Stream No.	46	47	48		
	Description	Water to makeup solution tank	Water to filter	Water to absorber		
1	Total stream, lb/hr	4,635	1,600	50,000		
2						
3						
4	sft^3/min (60°F)					
5	Temperature, °F					
6	Pressure, psig					
7	gpm	10	4	100		
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

TABLE 25. CITRATE PROCESS

BASE CASE EQUIPMENT LIST DESCRIPTION AND COST

Area 1--Materials Handling

	Item	No.	Description	Total material cost, 1979 $
1.	Conveyor, lime unloading	1	Belt, 12 in. wide x 200 ft long, 3 hp, 10 tons/hr, 100 ft/min	28,300
2.	Silo, lime storage	1	20 ft dia x 35 ft high, 10,750 ft^3, cone bottom, carbon steel	16,500
3.	Feeder, lime storage silo discharge	1	Rotary stargate, 1 hp, 5 tons/hr	1,800
4.	Conveyor/elevator, live lime feed	1	Redler Z type, 100 ft long, 3 hp, 5 tons/hr	13,300
5.	Bin, lime feed	1	10 ft dia x 10 ft high, 785 ft^3, cone bottom, carbon steel	3,000
	Vibrators	2		3,000
6.	Conveyor, soda ash and citric acid	1	Pneumatic, vacuum, 50 hp, 20 tons/hr	102,500
7.	Bin, soda ash storage	2	20 ft dia x 24 ft high, 7,540 ft^3, cone bottom, carbon steel	25,700
	Vibrators	2		3,000
8.	Bin, citric acid storage	1	9 ft dia x 8 ft high, 510 ft^3, cone bottom, carbon steel	2,200
	Vibrators	2		3,000
	Subtotal			202,300

(continued)

TABLE 25 (continued)

Area 2--Feed Preparation

	Item	No.	Description	Total material cost, 1979 $
1.	Feeder, soda ash bin discharge	2	Rotary stargate, 1/2 hp, 855 lb/hr	1,600
2.	Feeder, soda ash makeup conveyor	2	Weigh belt, 14 in. wide x 5 ft long, 1/2 hp, 855 lb/hr, variable speed	7,200
3.	Feeder, citric acid bin discharge	1	Rotary stargate, 1/2 hp, 75 lb/hr	800
4.	Feeder, citric acid makeup conveyor	1	Weigh belt, 14 in. wide x 5 ft long, 1/2 hp, 75 lb/hr, variable speed	3,500
5.	Conveyor, makeup solution tank	1	Belt, 12 in. wide x 40 ft long, 1/2 hp, 1,000 lb/hr, 100 ft/min	4,200
6.	Tank, makeup solution	1	7 ft dia x 8 ft high, 2,300 gal, open top, four 7 in. baffles, agitator supports, carbon steel	1,200
	Lining		1/4 in. neoprene lining	1,200
7.	Agitator, makeup solution tank	1	30 in. dia, 7-1/2 hp, neoprene coated	11,700
8.	Pump, makeup solution tank	2	Centrifugal, 10 gpm, 50 ft head, 1 hp, carbon steel, neoprene lined	2,300
	Subtotal			33,700

Area 3--Gas Handling

	Item	No.	Description	Total material cost, 1979 $
1.	Fans	4	Forced draft, 20 in. static head, 875 rpm, 2,000 hp, fluid drive, double width, double inlet	888,000
	Subtotal			888,000

(continued)

TABLE 25 (continued)

Area 4--SO_2 Absorption

Item	No.	Description	Total material cost, 1979 $
1. SO_2 absorber	4	Packed tower, 25 ft dia x 45 ft high, 5/8 in. carbon steel, FRP lining, 316 SS distributor plate, Inconel 625 spray header, 316 SS chevron vane entrainment separator; polypropylene cascade mini-ring packing	6,048,400
2. Pump, absorber makeup water	2	Centrifugal, 100 gpm, 150 ft head, 10 hp, carbon steel	4,000
3. Pump, presaturator liquor	6	Centrifugal, 1,262 gpm, 75 ft head, 50 hp, carbon steel, neoprene lined	38,400
4. Pump, presaturator makeup water	6	Centrifugal, 91 gpm, 150 ft head, 10 hp, carbon steel	12,000
5. Stripper, chloride purge	4	Packed column, 4 ft dia x 30 ft high, carbon steel	64,800
6. Compressor, stripper air	1	1,000 ft^3/min, 10 psig, 300 hp	71,400
7. Tank, effluent hold	4	14-1/2 ft dia x 14 ft high, 19,750 gal, open top, four 15 in. baffles, agitator supports, carbon steel	18,100
Lining		1/4 in. neoprene lining	17,500
8. Agitator, effluent hold tank	4	58 in. dia, 15 hp, neoprene coated	76,200
9. Pump, effluent hold tank	6	Centrifugal, 1,610 gpm, 120 ft head, 100 hp, carbon steel, neoprene lined	59,700
Subtotal			6,410,500

(continued)

TABLE 25 (continued)

Area 5--Reheat

	Item	No.	Description	Total material cost, 1979 $
1.	Reheater	4	Steam, tube type, 3,600 ft^2, one-half tubes made of Inconel 625 and one-half made of Cor-Ten	856,000
2.	Soot blowers	20	Air, retractable	130,000
	Subtotal			986,000

Area 6--Chloride Purge

	Item	No.	Description	Total material cost, 1979 $
1.	Feeder, lime feed bin discharge	1	Rotary stargate, 1/2 hp, 655 lb/hr	800
2.	Feeder, neutralization tank	1	Weigh belt, 14 in. wide x 5 ft long, 1/2 hp, 655 lb/hr, variable speed	7,100
3.	Tank, neutralization	1	6 ft dia x 7-1/2 ft high, 1,530 gal, open top, four 6 in. baffles, agitator supports, carbon steel	1,000
	Lining		1/4 in. neoprene lining	900
4.	Agitator, neutralization tank	1	24 in. dia, 7-1/2 hp, neoprene coated	6,300
5.	Pump, neutralization tank	2	Centrifugal, 48 gpm, 150 ft head, 7-1/2 hp, carbon steel, neoprene lined	5,400
	Subtotal			21,500

(continued)

TABLE 25 (continued)

Area 7--SO_2 Reduction

Item	No.	Description	Total material cost, 1979 $
1. Tank, SO_2 reduction (first)	1	16 ft dia x 24 ft high, 36,100 gal, convex dish head top and bottom, four 16 in. baffles, agitator supports, carbon steel, 30 psig operating pressure	12,400
Lining		1/4 in. neoprene lining	10,000
2. Agitator, SO_2 reduction tank	1	2 turbines, 66 in. dia, 50 hp, neoprene coated	48,000
3. Sparger, SO_2 reduction tank	1	5 ft dia ring of 10 in. schedule 40, 316 stainless steel	5,900
4. Pump, transfer	2	Centrifugal, 6,120 gpm, 60 ft head, 200 hp, carbon steel, neoprene lined	46,200
5. Tank, SO_2 reduction (second)	1	16 ft dia x 24 ft high, 36,100 gal, convex dish head top and bottom, four 16 in. baffles, agitator supports, carbon steel, 30 psig operating pressure	12,400
Lining		1/4 in. neoprene lining	10,000
6. Agitator, SO_2 reduction tank	1	2 turbines, 66 in. dia, 50 hp, neoprene coated	48,000
7. Sparger, SO_2 reduction	1	5 ft dia ring of 12 in. schedule 40, 316 stainless steel	7,300
8. Pump, sulfur slurry	2	Centrifugal, 6,540 gpm, 75 ft head, 250 hp, carbon steel, neoprene lined	52,200
9. Trap, reduction tank offgas	1	4 ft dia x 10 ft high, carbon steel, neoprene lined	1,500
10. Tank, aging	1	23 ft dia x 24 ft high, 74,600 gal, convex dish head top and bottom, four 23 in. baffles, agitator supports, carbon steel, 30 psig operating pressure	17,300

(continued)

TABLE 25 (continued)

Item	No.	Description	Total material cost, 1979 $
10. (continued)			
Lining		1/4 in. neoprene lining	16,300
11. Agitator, aging tank	1	92 in. dia, 30 hp, neoprene coated	31,300
Subtotal			318,800

Area 8--Sulfur Separation and Removal

Item	No.	Description	Total material cost, 1979 $
1. Tank, flotation	5	5 ft wide x 20 ft long x 5 ft deep, carbon steel, neoprene lined; skimmer with 2 hp motor	55,500
2. Compressor, flotation tank air	1	1,000 ft^3/min, 10 psig, 300 hp	71,400
3. Filter, flotation tank underflow	10	Rotary vacuum, 12 ft dia x 14 ft face, 20 total hp	1,256,600
4. Pump, filtrate	6	Centrifugal, 1,500 gpm, 40 ft head, 50 hp, carbon steel, neoprene lined	38,400
5. Tank, liquor hold	1	20 ft dia x 30 ft high, 70,500 gal, closed top, four 20 in. baffles, agitator supports, carbon steel	14,200
Lining		1/4 in. neoprene lining	13,600
6. Agitator, liquor hold tank	1	2 turbines, 84 in. dia, 40 hp, neoprene coated	41,500
7. Pump, scrubbing liquor return	6	Centrifugal, 1,590 gpm, 100 ft head, 75 hp, carbon steel, neoprene lined	58,000
8. Pump, cooler feed	2	Centrifugal, 60 gpm, 50 ft head, 2 hp, carbon steel, neoprene lined	4,100

(continued)

TABLE 25 (continued)

	Item	No.	Description	Total material cost, 1979 $
9.	Tank, sulfur slurry	1	10 ft dia x 10 ft high, 5,900 gal, closed top, cone bottom, carbon steel	2,900
	Lining		1/4 in. neoprene lining	2,600
10.	Pump, sulfur melter feed	2	Screw type, 100 gpm, 160 ft head, 10 hp, 316 stainless steel	7,900
11.	Melter, sulfur	1	Shell and tube, 1,140 ft^2, 316 stainless steel, insulated	59,900
12.	Tank, sulfur settler	1	9 ft dia x 13-1/2 ft long, convex dish head top and bottom, 316 stainless steel	10,900
	Insulation		Fiberglass	2,100
	Heater	1	Steam, 100 ft^2, 316 stainless steel	2,600
13.	Flash drum, sulfur settler	1	4 ft dia x 5-1/2 ft long, 316 stainless steel	1,700
14.	Fan, vent line exhaust	1	1,000 ft^3/min, 5 hp	700
	Subtotal			1,644,600

Area 9--Sulfur Storage and Shipping

	Item	No.	Description	Total material cost, 1979 $
1.	Pit, sulfur receiving	1	10 ft wide x 10 ft long x 10 ft deep, w/cover, 304 stainless steel	10,400
	Insulation		Fiberglass	2,500
	Heater	1	Steam, 100 ft^2, 400 ft of 1 in. schedule 40, 304 stainless steel	2,500
2.	Pump, sulfur transfer	2	Submerged, high temperature, 15 gpm, 100 ft head, 1-1/2 hp, 316 stainless steel, steam traced, insulated	5,500

(continued)

TABLE 25 (continued)

Item	No.	Description	Total material cost, 1979 $
3. Tank, sulfur storage	1	43 ft dia x 41 ft high, 467,100 gal, closed top, 304 stainless steel	147,000
Insulation		Fiberglass	29,500
4. Heater	1	Steam, 300 ft^2, 1,200 ft of 1 in. schedule 40, 304 stainless steel	6,400
5. Pump, sulfur shipping	2	Submerged, high temperature, 60 gpm, 100 ft head, 5 hp, 316 stainless steel, steam traced, insulated	7,100
Subtotal			210,900

Area 10--Sulfate Purge

Item	No.	Description	Total material cost, 1979 $
1. Cooler, sulfate purge stream	1	700 ft^2, 316 stainless steel	35,800
2. Pump, liquor return	2	Centrifugal, 60 gpm, 60 ft head, 2 hp, carbon steel, neoprene lined	4,100
3. Crystallizer, sulfate	1	3 ft dia x 12 ft high, 4,500 gal, closed top, four 8 in. baffles, agitator supports, 200 ft^2 cooling coil	11,200
Insulation		Polyurethane foam	1,400
4. Agitator, sulfate crystallizer	1	32 in. dia, 10 hp, neoprene coated	12,000
5. Pump, centrifuge feed	2	Centrifugal, 60 gpm, 60 ft head, 2 hp, carbon steel, neoprene lined	4,100
6. Centrifuge, sulfate purge	1	Solid bowl, 36 in. dia x 84 in. long, 200 hp, insulated	176,100

(continued)

TABLE 25 (continued)

Item	No.	Description	Total material cost, 1979 $
7. Conveyor, sulfate removal	1	Belt, 12 in. wide x 20 ft long, 1 hp, 2,990 lb/hr	3,900
8. Tank, centrate surge	1	7 ft dia x 7 ft high, 2,000 gal, closed top, carbon steel	1,200
Lining		Neoprene lining	800
9. Pump, centrate return	2	Centrifugal, 60 gpm, 60 ft head, 2 hp, carbon steel, neoprene lined	4,100
10. Tank, refrigerant surge	1	8 ft dia x 6 ft high, 2,250 gal, closed top, carbon steel	1,300
Insulation		Polyurethane foam	800
11. Pump, cooling water	2	Centrifugal, 247 gpm, 150 ft head, 20 hp, carbon steel	5,800
12. Refrigeration system	1	200 tons	47,000
Subtotal			309,600

Area 11--H_2S Generation

Item	No.	Description	Total material cost, 1979 $
1. H_2S generator	1	300 tons/day, battery limit, installed cost	5,850,000
Subtotal			5,850,000

Area 12--H_2 Generation

Item	No.	Description	Total material cost, 1979 $
1. H_2 generator	1	20 tons/day, battery limit, installed cost	4,680,000
Subtotal			4,680,000

Major Process Areas

The citrate process has been divided into the following operating areas:

1. Materials handling. Facilities for receiving and storing lime, soda ash, and citric acid are included in this area. The solids handling and storage equipment for crystalline citric acid is eliminated at the demonstration plant by purchasing citric acid as a 50 weight percent liquid. Makeup citric acid solution is added in truckload batches directly to a liquor hold tank.

2. Feed preparation. This area includes facilities for producing a solution of makeup soda ash and citric acid.

3. Gas handling. Fan location and duct configuration are the same as the limestone slurry process.

4. SO_2 absorption. Four packed-tower absorbers with presaturators, effluent hold tanks and pumps are provided. Also included are SO_2 strippers and air compressor. For this study a carbon steel absorber with an FRP liner has been specified. Field applied flakeglass lining of the absorber is specified at the demonstration plant.

5. Stack gas reheat. Equipment in this area includes indirect steam reheaters and soot blowers for the coal-fired cases. The oil-fired unit is designed with one direct oil-fired reheater per duct which discharges hot combustion gases directly into the duct.

6. Chloride purge. This area includes facilities for neutralizing with lime a purge stream of presaturator liquor for the control of chloride buildup in the system.

7. SO_2 reduction. In this area, H_2S gas contacts the SO_2-rich sorbent in reduction (reactor) tanks to produce elemental sulfur. Both the transfer pump for circulating citrate solution between reactors and the sulfur slurry pump to feed solution containing sulfur crystals to the flotation tank have been eliminated in the demonstration-plant design by using gravity flow in a cascading elevation sequence.

8. Sulfur separation and removal. Facilities are provided to separate sulfur particles from the slurry liquor and heat the sulfur to the molten state. Based on pilot plant operation data, filtration of regenerated solution has been discontinued. Filtration of the regenerated solution was used in development work on the process but was not considered necessary in scaleup to demonstration plant magnitude. The absorber packing is considered sufficiently washed by solution so that sulfur and ash particles will not foul the system. The regenerated solution underflow from the flotation tank flows by gravity directly to the liquor hold tank.

A flash system for letdown of pressure on the citrate solution leaving the sulfur settler tank has not performed reliably in pilot plant operation. When the citrate solution flashes to a reduced pressure, sufficient water is vaporized to cause citrate sulfate crystals to form in the flash system and cause plugging. The vapors leaving the flash drum are corrosive and must be condensed in order to return to the liquor hold tank. The Bureau of Mines system quenches the hot solution before pressure letdown.

9. Sulfur storage and shipping. A receiving pit and sulfur storage tank are provided in this area. A below-ground concrete pit or an insulated carbon steel tank can be used for molten sulfur storage.

10. Sulfate purge. A purge stream of scrubbing liquor is routed to the purge treatment area for removal of sodium sulfate from the system. Equipment for the crystallization, separation, and removal of sodium sulfate is included in this area. The Bureau of Mines demonstration unit does not include filtration of the slipstream to the sulfate purge area.

    The unit uses an evaporative-cooled crystallizer system to chill the purge stream to about 39°F which produces sodium sulfate decahydrate crystals. The sulfate crystals are screened from the citrate solution. The residual solution removed with the crystals provides an additional purge from the system of accumulated chlorides and entrained solids.

11. H_2S generation. This area includes one complete H_2S generation unit with a capacity of 300 tons H_2S per day. The Bureau of Mines system uses an H_2S generator developed and licensed by the Home Oil Company, Ltd., of Canada. The generator design was adapted for use with the Bureau of Mines citrate system in the pilot stage of process development. The generator consumes natural gas, steam and molten sulfur to produce a product gas containing about 78% H_2S on a dry basis. Reductant gas feedstocks other than natural gas can be used. Propane, carbon monoxide, hydrogen, and methanol have been demonstrated. The molten sulfur source is provided by inventory from the citrate process. The generator is provided as a package plant.

12. H_2 generation. A 20-ton-per-day H_2 generation unit using natural gas as feedstock produces the required reducing gas for H_2S production. This area is combined with area 11 at the Bureau of Mines demonstration site.

Storage Capacity

Storage requirements for raw materials and allowances for in-process streams are listed below.

Raw materials:
  - Lime storage silo - 30 days
  - Soda ash storage bin - 10 days
  - Citric acid storage bin - 15 days

In-process storage:
  - Makeup solution tank - 4 hours
  - Effluent hold tank - 5 minutes
  - Neutralization tank - 30 minutes
  - SO_2 reduction tanks - 5 minutes each
  - Aging tank - 10 minutes
  - Liquor hold tank - 10 minutes

Product storage:
  - Sulfur storage tank - 30 days

Chloride Purge

Unlike the waste-producing processes which trap enough chloride in the interstitial water of the settled sludge to maintain a steady-state chloride concentration in the recycle liquor, chlorides in a recovery process can build up over a period of time and thereby cause problems of product quality and equipment corrosion. A purge is added to the citrate process to control chloride buildup in the system. For this study it is assumed that the lime-neutralized purge stream for chloride control is pumped to the fly ash pond for disposal. However, this method may be environmentally unacceptable if seepage of calcium chloride from the ash pond contaminates underground or nearby water sources. Although several methods of control such as special pond liners and reverse osmosis are available, the scope of this study does not include the evaluation of water treatment systems.

ECONOMIC EVALUATION AND COMPARISON

Based on the design and economic conditions described in Design and Economic Premises section and the material balance and equipment requirements of each process detailed in Systems Estimated, capital investment and annual and lifetime revenue requirements have been projected for the economic evaluation and comparison of the three processes. All the possible design and economic configurations, variations, and combinations encountered in site-specific applications of these processes cannot be covered in this study. However, it is expected that the procedures used in preparing this evaluation are sufficiently discussed to allow adjustment of results to fit the many possible applications.

CAPITAL INVESTMENT

Results

The projected capital investment estimates are calculated in 1979 dollars. Three methods are used for displaying the results.

1. Total capital investment requirements - tabular investment results for all case variations. For each of the three processes, a summary table is presented listing the projected total capital investment requirements for the case variations, expressed as total dollars and dollars per kW (Tables 26-28).

2. Summary of estimated capital investment - summarized area costs for all case variations studies. A summary of estimated capital investment is presented in the appendix for each of the projected case variations.

3. Total capital investment requirements - base case process equipment and installation analysis. Tables 29-31 show summarized area-by-area equipment costs along with installation expense. For all three process displays, these costs are itemized separately and displayed according to the material and labor component of each. The area analysis tables show the distribution of total investment as a percent of direct investment.

TABLE 26. LIMESTONE SLURRY PROCESS

TOTAL CAPITAL INVESTMENT SUMMARY[a]

Case	Years remaining life	Total capital investment, $	$/kW
Coal-Fired Power Unit			
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)			
200 MW E 3.5% sulfur	20	25,057,000	125.3
200 MW N 3.5% sulfur	30	25,461,000	127.3
500 MW E 3.5% sulfur	25	50,120,000	100.2
500 MW N 2.0% sulfur	30	39,641,000	79.3
500 MW N 3.5% sulfur	30	48,728,000	97.5
500 MW N 5.0% sulfur	30	54,621,000	109.2
1,000 MW E 3.5% sulfur	25	74,830,000	74.8
1,000 MW N 3.5% sulfur	30	71,423,000	71.4
Solids disposal by trucking			
500 MW N 3.5% sulfur	30	42,307,000	84.6
90% SO_2 removal; onsite solids disposal (ponding)			
500 MW N 3.5% sulfur	30	50,437,000	100.9
Oil-Fired Power Unit			
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)			
500 MW E 2.5% sulfur	25	38,400,000	77.0

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a. Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mile from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE 27. GENERIC DOUBLE-ALKALI PROCESS

TOTAL CAPITAL INVESTMENT SUMMARY[a]

Case	Years remaining life	Total capital investment, $	$/kW
Coal-Fired Power Unit			
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)			
200 MW E 3.5% sulfur	20	26,006,000	130.0
200 MW N 3.5% sulfur	30	25,477,000	127.4
500 MW E 3.5% sulfur	25	53,675,000	107.4
500 MW N 2.0% sulfur	30	42,110,000	84.2
500 MW N 3.5% sulfur	30	50,551,000	101.1
500 MW N 5.0% sulfur	30	57,579,000	115.2
1,000 MW E 3.5% sulfur	25	85,487,000	85.5
1,000 MW N 3.5% sulfur	30	79,016,000	79.0
Solids disposal by trucking			
500 MW N 3.5% sulfur	30	41,335,000	82.7
90% SO_2 removal; onsite solids disposal (ponding)			
500 MW N 3.5% sulfur	30	52,404,000	104.8
Oil-Fired Power Unit			
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)			
500 MW E 2.5% sulfur	25	40,260,000	80.5

[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mile from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE 28. CITRATE PROCESS

TOTAL CAPITAL INVESTMENT SUMMARY[a]

Case	Years remaining life	Total capital investment, $	$/kW
Coal-Fired Power Unit			
1.2 lb SO_2/MBtu heat input allowable emission			
200 MW E 3.5% sulfur	20	38,788,000	193.9
200 MW N 3.5% sulfur	30	38,075,000	190.9
500 MW E 3.5% sulfur	25	72,605,000	145.2
500 MW N 2.0% sulfur	30	58,098,000	116.2
500 MW N 3.5% sulfur	30	71,639,000	143.3
500 MW N 5.0% sulfur	30	82,572,000	165.1
1,000 MW E 3.5% sulfur	25	109,024,000	109.0
1,000 MW N 3.5% sulfur	30	106,589,000	106.6
90% SO_2 removal			
500 MW N 3.5% sulfur	30	74,624,000	149.2
Oil-Fired Power Unit			
0.8 lb SO_2/MBtu heat input allowable emission			
500 MW E 2.5% sulfur	25	52,442,000	104.9

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE 29. LIMESTONE SLURRY PROCESS BASE CASE - DIRECT INVESTMENT - PROCESS EQUIPMENT AND INSTALLATION COSTS (k$)

Direct Investment	Materials handling	Feed preparation	Gas handling	SO_2 absorption	Stack gas reheat	Solids disposal	Total	% of total direct investment	% of total capital investment
Equipment									
Material	486	634	812	3,792	986	47	6,757	26.0	13.9
Labor	106	104	78	773	122	17	1,200	4.6	2.5
Piping and insulation									
Material	13	181	-	1,905	57	885	3,041	11.7	6.2
Labor	3	88	-	599	38	367	1,095	4.2	2.2
Ductwork, chutes, and supports									
Material	-	-	1,562	-	-	-	1,562	6.0	3.2
Labor	-		1,187	-	-	-	1,187	4.6	2.4
Concrete foundations									
Material	112	55	12	74	-	12	265	1.0	0.5
Labor	452	212	51	207	-	35	957	3.7	2.0
Excavation, site preparation Railroads, roads, and pond	-	-	-	-	-	8	8	-	-
Structural									
Material	254	-	-	164	-	1	419	1.6	0.9
Labor	91	-	19	399	-	12	521	2.0	1.1
Electrical									
Material	62	92	195	148	1	62	560	2.2	1.2
Labor	158	176	347	251	2	183	1,117	4.3	2.3
Instruments									
Material	11	66	46	490	63	6	682	2.6	1.4
Labor	3	16	8	91	12	2	132	0.5	0.3
Paint and miscellaneous									
Material	1	1	-	4	-	3	9	-	-
Labor	7	8	1	21	1	18	56	0.2	0.1
Buildings									
Material	-	39	-	-	-	-	39	0.2	0.1
Labor	-	68	-	-	-	-	68	0.3	0.1
Subtotal	1,759	1,740	4,318	8,918	1,282	1,658	19,675	75.7	40.4
Services, utilities, and miscellaneous	-	-	-	-	-	-	1,180	4.5	2.4
Total excluding pond construction	1,759	1,740	4,318	8,918	1,282	1,658	20,855	80.2	42.8
Pond construction	-	-	-	-	-	-	5,145	19.8	10.6
Total direct investment	1,759	1,740	4,318	8,918	1,282	1,658	26,000	100.0	53.4
Percent of total direct investment	6.8	6.7	16.6	34.3	4.9	6.4			

TABLE 30. GENERIC DOUBLE-ALKALI PROCESS BASE CASE - DIRECT INVESTMENT - PROCESS EQUIPMENT AND INSTALLATION COSTS (k$)

Direct Investment	Materials handling	Feed preparation	Gas handling	SO_2 absorption	Stack gas reheat	Reaction	Solids separation	Solids disposal	Total	% of total direct investment	% of total capital investment
Equipment											
Material	533	288	752	4,006	986	127	907	37	7,636	28.4	15.1
Labor	378	94	68	1,473	122	75	530	16	2,756	10.3	5.5
Piping and insulation											
Material	-	23	-	1,298	57	22	206	481	2,087	7.8	4.1
Labor	-	24	-	620	38	19	179	36	1,247	4.7	2.5
Ductwork, chutes, and supports											
Material	-	-	1,562	-	-	-	-	-	1,562	5.8	3.1
Labor	-	-	1,187	-	-	-	-	-	1,187	4.4	2.3
Concrete foundations											
Material	36	9	12	62	-	8	19	12	158	0.6	0.3
Labor	94	25	51	172	-	22	51	33	448	1.7	0.9
Excavation, site preparation Railroads, roads, and pond	-	-	-	-	-	-	27	8	35	0.1	0.1
Structural											
Material	129	-	-	160	-	14	10	2	315	1.2	0.6
Labor	46	-	19	388	-	6	4	6	469	1.8	0.9
Electrical											
Material	183	69	195	206	1	13	95	62	824	3.1	1.6
Labor	208	80	347	232	2	38	152	191	1,250	4.7	2.5
Instruments											
Material	58	142	46	462	63	7	101	7	886	3.3	1.8
Labor	28	70	8	86	12	3	46	4	257	1.0	0.5
Paint and miscellaneous											
Material	2	1	-	5	-	2	4	3	17	0.1	-
Labor	15	8	1	36	1	1	17	18	97	0.4	0.2
Buildings											
Material	-	-	-	-	-	-	4	-	4	-	-
Labor	-	-	-	-	-	-	-	-	-	-	-
Subtotal	1,710	833	4,248	9,206	1,282	357	2,352	1,247	21,235	79.4	42.0
Services, utilities, and miscellaneous	-	-	-	-	-	-	-	-	1,274	4.8	2.5
Total excluding pond construction	1,710	833	4,248	9,206	1,282	357	2,352	1,247	22,509	84.2	44.5
Pond construction	-	-	-	-	-	-	-	-	4,241	15.8	8.4
Total direct investment	1,710	833	4,248	9,206	1,282	357	2,352	1,247	26,750	100.0	52.9
Percent of total direct investment	6.4	3.1	15.9	34.4	4.8	1.3	8.8	4.7			

TABLE 31. CITRATE PROCESS BASE CASE - DIRECT INVESTMENT - PROCESS EQUIPMENT AND INSTALLATION COSTS (k$)

Direct Investment	Materials handling	Feed preparation	Gas handling	SO_2 absorption	Stack gas reheat	Chloride purge	SO_2 reduction	Sulfur separation and removal	Sulfur storage and shipping	Sulfate purge	H_2S generation	H_2 generation	Total	% of total direct investment	% of total capital investment
Equipment															
Material	202	34	888	6,410	986	22	319	1,645	211	310	-	-	11,027	29.9	15.4
Labor	116	9	92	2,105	122	4	183	266	280	83	-	-	3,260	8.8	4.6
Piping and insulation															
Material	-	3	-	1,040	57	9	24	88	42	97	-	-	1,360	3.7	1.9
Labor	-	7	-	960	38	3	56	82	78	73	-	-	1,297	3.5	1.8
Ductwork, chutes, and supports															
Material	-	-	1,406	-	-	-	200	86	-	-	-	-	1,692	4.6	2.4
Labor	-	-	1,068	-	-	-	150	64	-	-	-	-	1,282	3.5	1.8
Concrete foundations															
Material	24	2	6	78	-	1	14	12	10	4	-	-	151	0.4	0.2
Labor	64	4	15	212	-	3	36	31	26	11	-	-	402	1.1	0.6
Excavation, site preparation															
Railroads, roads, and pond	-	-	-	-	-	1	-	-	17	-	-	-	18	-	-
Structural															
Material	52	2	12	380	-	1	13	2	-	-	-	-	462	1.3	0.6
Labor	32	1	7	170	-	1	7	2	-	1	-	-	221	0.6	0.3
Electrical															
Material	61	11	276	91	1	13	45	162	31	91	-	-	782	2.1	1.1
Labor	114	19	268	259	2	19	30	176	44	259	-	-	1,190	3.2	1.7
Instruments															
Material	57	19	37	369	63	10	13	40	20	40	-	-	668	1.8	0.9
Labor	31	11	17	181	12	5	7	20	10	20	-	-	314	0.9	0.4
Paint and miscellaneous															
Material	4	1	-	5	-	1	1	1	1	1	-	-	15	-	-
Labor	13	5	1	25	1	4	2	4	2	4	-	-	61	0.2	0.1
Buildings															
Material	-	3	-	-	-	-	-	20	-	-	-	-	23	0.1	-
Labor	-	1	-	-	-	-	-	5	-	-	-	-	6	-	-
Battery limits											5,850	4,680	10,530	28.6	14.7
Subtotal	770	132	4,093	12,285	1,282	97	1,100	2,706	772	994	5,850	4,680	34,761	94.3	48.5
Services, utilities, and miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	2,086	5.7	2.9
Total direct investment	770	132	4,093	12,285	1,282	97	1,100	2,706	772	994	5,850	4,680	36,847	100.0	51.4
Percent of total direct investment	2.1	0.4	11.1	33.2	3.5	0.3	3.0	7.3	2.1	2.7	15.9	12.7			

Discussion of Results

The capital investment costs for limestone and double alkali are quite close; the relative simplicity of limestone scrubbing offset by smaller pond requirements in double alkali. The projected total investments for the limestone slurry process range from $25,057,000 ($125.3/kW) for an existing 200-MW 3.5% sulfur coal-fired unit to $74,830,000 ($74.8/kW) for an existing 1,000-MW 3.5% sulfur coal-fired unit. Investments for the generic double-alkali process range from $25,477,000 ($127.4/kW) for a new 200-MW 3.5% sulfur coal-fired unit to $85,487,000 ($85.5/kW) for an existing 1,000-MW 3.5% sulfur coal-fired unit.

Understandably, the product-producing citrate process has greater capital investment requirements than the waste-producing processes. The projected capital investments for citrate range from $38,075,000 ($190.9/kW) for a new 200-MW 3.5% sulfur coal-fired unit to $109,024,000 ($109.0/kW) for an existing 1,000-MW 3.5% sulfur coal-fired unit.

The summarized capital investment results for the three processes are shown in Figures 14-16 which indicate the effect of power unit size and sulfur content of coal on the total fixed investment for units of different status (new or existing). The effects of similar variations on capital investment in dollars per kW are given in Figures 17-19.

A variation of the base case was prepared for the waste-producing processes in which the waste solids are disposed of by trucking to the disposal area. This is the single case variation comparison between limestone and double alkali in which double alkali has a lower investment requirement ($41,353,000 for double alkali and $42,307,000 for limestone). While the double-alkali process includes thickening and filtration as a normal process step, it must be added to the limestone system to produce a truckable filter cake. In addition, limestone FGD produces more waste solids because of a higher stoichiometric ratio of calcium to SO_2 removed and it includes a more expensive feed preparation area. These factors combine to produce a limestone investment that is 2.4% higher than the double-alkali case. When the double-alkali disposal-by-trucking case is compared with the limestone base case (slurry disposal by ponding) the limestone capital investment requirement is 18% higher. Table 32 is a comparison of capital investment costs for the disposal alternatives.

TABLE 32. COMPARISON OF INVESTMENT

REQUIREMENTS FOR SOLIDS DISPOSAL ALTERNATIVES[a]

Process	Slurry ponding, $ (base case)	Filter cake trucking, $	Investment decrease in trucking alternative $	%
Limestone	48,728,000	42,307,000	6,421,000	13.2
Double alkali	50,551,000	41,335,000	9,216,000	18.2

a. Base case conditions: Pond and cake disposal are both 1 mile from scrubbing facilities.

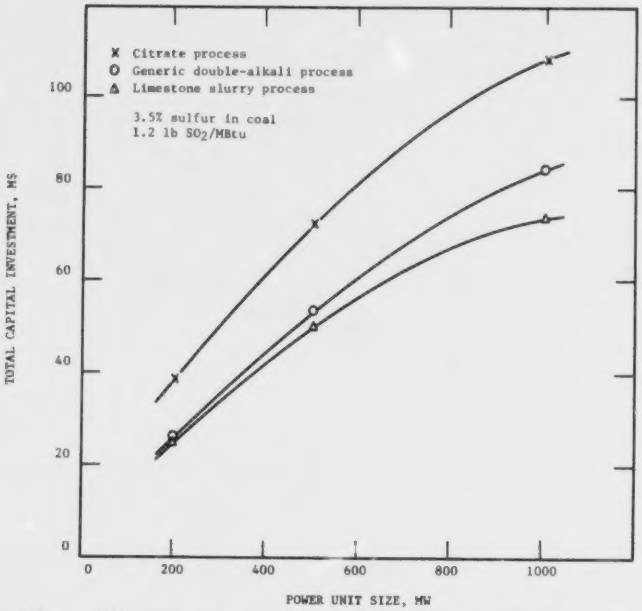

Figure 14. All processes. Effect of power unit size on total capital investment for new coal-fired units.

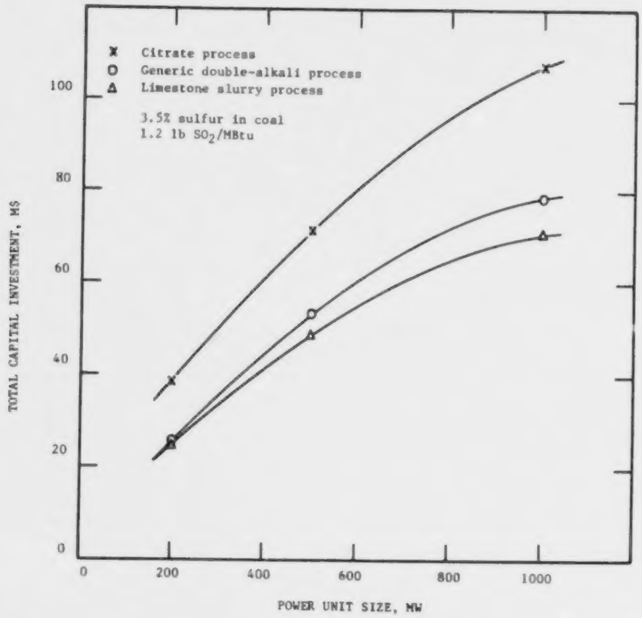

Figure 15. All processes. Effect of power unit size on total capital investment for existing coal-fired units.

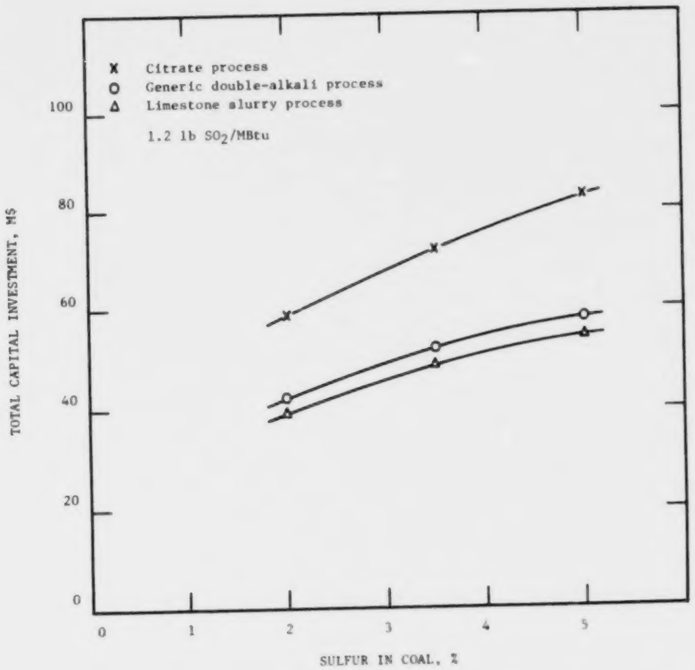

Figure 16. All processes. Effect of sulfur content of coal on total capital investment for new 500-MW units.

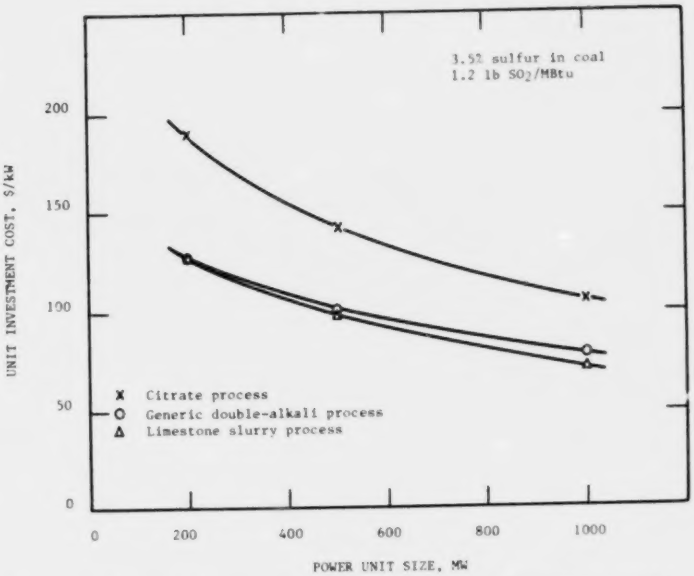

Figure 17. All processes. Effect of power unit size on unit investment cost for new coal-fired units.

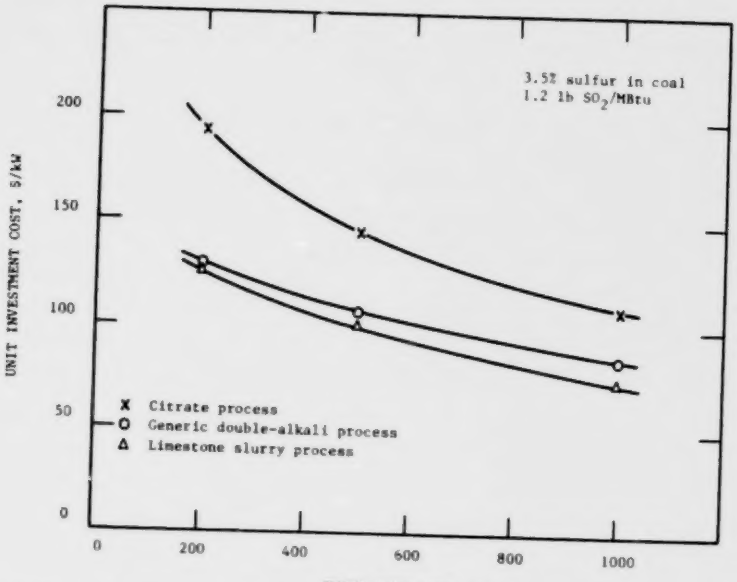

Figure 18. All processes. Effect of power unit size on unit investment cost for existing coal-fired units.

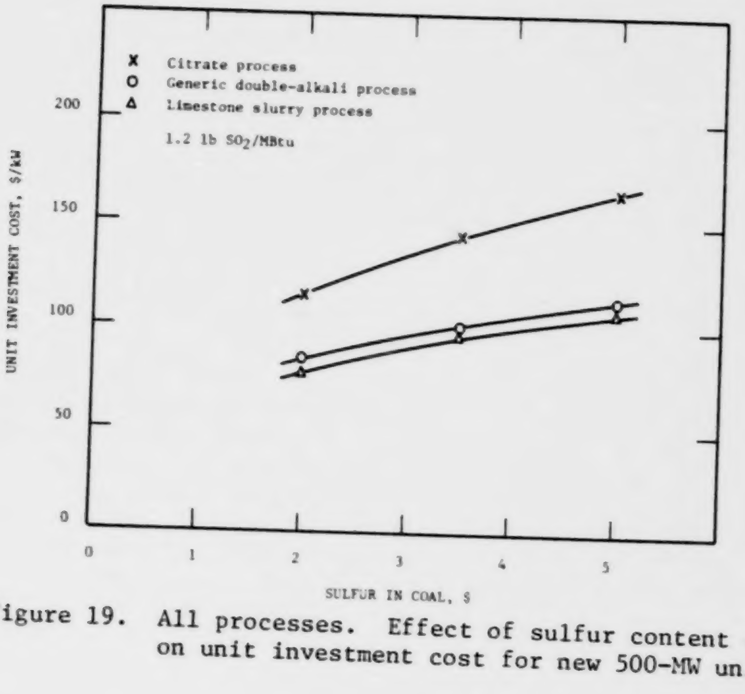

Figure 19. All processes. Effect of sulfur content of coal on unit investment cost for new 500-MW units.

The difference in investment requirements for SO_2 removal at base case conditions (1.2 lb SO_2/MBtu heat input allowable emissions) versus 90% SO_2 removal for each process is displayed in Table 33. Capital investment increases range from 3.5% to 4.2% or from an increase of $1,709,000 additional capital required for limestone to $2,985,000 additional capital required for citrate.

TABLE 33. COMPARISON OF INVESTMENT

REQUIREMENTS FOR DIFFERENT SO_2 REMOVAL LEVELS

Process	Projected total capital investment requirements, $ 500-MW new 3.5% sulfur coal-fired units: 1.2 lb SO_2/MBtu heat input allowable emission	Projected total capital investment requirements, $ 500-MW new 3.5% sulfur coal-fired units: 90% SO_2 removal	Investment increase resulting from increased SO_2 removal to 90%: $	Investment increase resulting from increased SO_2 removal to 90%: %
Limestone	48,728,000	50,437,000	1,709,000	3.5
Double alkali	50,551,000	52,404,000	1,853,000	3.7
Citrate	71,639,000	74,624,000	2,985,000	4.2

Differences in capital investment requirements between processes, between new and existing units, or between sulfur content of fuels can best be analyzed by studying the specific unit areas within the processes. Base case summarized area equipment-and-installation breakdowns which give component costs for the three processes are shown in Tables 29-31. In each process the greatest fraction of the investment cost is attributed to the SO_2 absorption area, approximately 33% to 34% of the direct investment for base case conditions. Gas handling (contributing from 11% to 17% for the base case) and pond construction (contributing from 16% in double alkali to 20% in the limestone base case) also are significant portions of the direct investment. In the citrate process, the H_2 and H_2S generation plants represent approximately 29% of the direct investment. Special purging of chlorides in systems producing salable abatement products such as the citrate process accounts for only 0.3% of the direct investment in the citrate base case.

In a comprehensive area-by-area comparison of capital investment requirements for all case variations (see tables in appendix) the SO_2 absorption area cost ranges from 29% to 43% of the direct investment. The effect of plant age on investment costs becomes important in waste-producing processes where pond size and construction costs depend on remaining plant life. For example, the cost of pond construction for the double-alkali 200-MW new coal-fired unit (30-year remaining life) is $2,141,000 while the pond construction cost for a 200-MW existing coal-fired unit (20-year remaining life) is $1,197,000. The H_2 and H_2S generation plants represent 22% to 33% of the citrate direct investment. Chloride purge facilities account for less than 1% of citrate direct investment for all case variations.

Capital investment and revenue requirements are now available for a number of limestone FGD units. A citrate system and several double-alkali units are under construction. As costs for these become available, comparisons with the results of this study are to be expected. Care must be taken in these comparisons to understand the scope of the work and to determine the areas that may not be directly comparable. The base case (500-MW 3.5% sulfur new coal-fired unit) capital investment for limestone slurry scrubbing derived in this study is \$97.5/kW. As an example of how changes in scope affect the capital investment, Table 34 defines area-cost increases which total \$96/kW or a new capital investment for limestone of \$193.5/kW. Contractor bid competition, construction experience, and changes and refinements in process design will affect the actual costs of installing and operating a large-scale system. Ultimately, demonstrated performance of any FGD system will produce the necessary data for full understanding of process costs.

REVENUE REQUIREMENTS

Results

Annual and lifetime revenue requirements for the three processes are calculated on a regulated economics basis. The projected annual revenue requirements are calculated in 1980 dollars.

Annual Revenue Requirements--

Three methods for displaying results are presented.

1. Summary of average annual revenue requirements - tabular revenue requirement results for all case variations. For each of the three processes, a summary table is presented listing the projected total average annual revenue requirements for the case variations, expressed as total dollars and equivalent unit costs (Tables 35-37).

2. Projected average annual revenue requirements - all case variations for three processes. Summary tables showing changes in process costs and the corresponding equivalent unit revenue requirements are presented in the appendix for the case variations studied for each process. The distribution of revenue requirement components is expressed as a percent of the total average annual revenue requirements.

3. Average annual revenue requirements - base case operating breakdown analysis. Summarized by operating area, revenue requirements are projected according to direct cost components (Tables 38-40).

Lifetime Revenue Requirements--

Results of the lifetime economic projections are presented.

1. Tables 41-43 summarizing the lifetime economics results for each case variation.

2. Computer printouts of the detailed year-by-year cash flow analyses, displayed in the appendix, for each case variation of each process.

TABLE 34. LIMESTONE SLURRY PROCESS

ADDITIONAL INVESTMENT REQUIRED FOR MODIFIED PROJECT SCOPE

	Investment required, $/kW
Base case - limestone slurry process: 500-MW new unit burning coal containing 3.5% sulfur, 16% ash, 10,500 Btu/lb heat value; 1.2 lb SO_2 allowable emission per MBtu heat input; 0.1% liquid entrainment in cleaned stack gas; 30-year life, 127,500-hr operation; no redundancy; 20% contingency; onsite solids disposal; mid-1979 cost basis	97.5
	Additional investment required, $/kW
Modified case: 500-MW new unit burning coal containing 6% sulfur, 16% ash, 10,500 Btu/lb heat value; 90% SO_2 removal; 0.3% liquid entrainment in cleaned stack gas; 30-year life, 127,500-hr operation; 50% redundancy; onsite solids disposal; mid-1979 cost basis	
Investment increases due to:	
Increased raw material handling	18.3
Larger waste disposal area and pond	46.9
50% redundancy of ball mills, scrubbers, and other equipment	30.8
Total increase in capital investment	96.0

TABLE 35. LIMESTONE SLURRY PROCESS

ANNUAL REVENUE REQUIREMENTS SUMMARY[a]

Case	Years remaining life	Total annual revenue requirements	Mills/kWh	$/ton (bbl) of coal (oil) burned	$/MBtu heat input	$/ton sulfur removed
Coal-Fired Power Unit						
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)						
200 MW E 3.5% sulfur	20	7,479,400	5.34	11.81	0.56	506.05
200 MW N 3.5% sulfur	30	7,153,200	5.11	11.67	0.56	499.87
500 MW E 3.5% sulfur	25	14,789,400	4.23	9.65	0.46	413.34
500 MW N 2.0% sulfur	30	11,624,900	3.32	7.75	0.37	717.59
500 MW N 3.5% sulfur	30	14,101,900	4.03	9.40	0.45	402.91
500 MW N 5.0% sulfur	30	16,032,200	4.58	10.69	0.51	295.91
1,000 MW E 3.5% sulfur	25	23,241,200	3.32	7.75	0.37	332.02
1,000 MW N 3.5% sulfur	30	21,874,300	3.12	7.54	0.36	323.25
Solids disposal by trucking						
500 MW N 3.5% sulfur	30	15,172,400	4.33	10.11	0.48	433.50
90% SO_2 removal; onsite solids disposal (ponding)						
500 MW N 3.5% sulfur	30	14,651,300	4.19	9.77	0.47	358.22
Oil-Fired Power Unit						
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)						
500 MW E 2.5% sulfur	25	11,446,600	3.27	2.15	0.35	770.81

[a] Basis

Midwest plant location, 1980 revenue requirements.
Power unit on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Investment and revenue requirement for removal and disposal of fly ash excluded.

TABLE 36. GENERIC DOUBLE-ALKALI PROCESS

ANNUAL REVENUE REQUIREMENTS SUMMARY[a]

Case	Years remaining life	Total annual revenue requirements	Mills/kWh	$/ton (bbl) of coal (oil) burned	$/MBtu heat input	$/ton sulfur removed
Coal-Fired Power Unit						
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)						
200 MW E 3.5% sulfur	20	7,553,000	5.40	11.92	0.57	511.03
200 MW N 3.5% sulfur	30	7,169,100	5.12	11.69	0.56	500.99
500 MW E 3.5% sulfur	25	15,441,700	4.41	10.07	0.48	431.57
500 MW N 2.0% sulfur	30	11,335,300	3.24	7.56	0.36	699.71
500 MW N 3.5% sulfur	30	14,676,000	4.19	9.78	0.47	419.31
500 MW N 5.0% sulfur	30	17,741,900	5.07	11.83	0.56	327.46
1,000 MW E 3.5% sulfur	25	25,750,900	3.68	8.58	0.41	367.87
1,000 MW N 3.5% sulfur	30	24,147,700	3.45	8.33	0.40	356.84
Solids disposal by trucking						
500 MW N 3.5% sulfur	30	14,293,900	4.08	9.53	0.45	408.40
90% SO_2 removal; onsite solids disposal (ponding)						
500 MW N 3.5% sulfur	30	15,438,800	4.41	10.29	0.49	387.90
Oil-Fired Power Unit						
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)						
500 MW E 2.5% sulfur	25	11,128,400	3.18	2.09	0.34	749.39

a. Basis
Midwest plant location, 1980 revenue requirements.
Power unit on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Investment and revenue requirement for removal and disposal of fly ash excluded.

TABLE 37. CITRATE PROCESS

ANNUAL REVENUE REQUIREMENTS SUMMARY[a]

Case	Years remaining life	Total annual revenue requirements	Mills/kWh	\$/ton (bbl) of coal (oil) burned	\$/MBtu heat input	\$/ton sulfur removed	\$/ton sulfur recovered
Coal-Fired Power Unit							
1.2 lb SO_2/MBtu heat input allowable emission							
200 MW E 3.5% sulfur	20	12,289,200	8.78	19.40	0.92	831.47	859.99
200 MW N 3.5% sulfur	30	11,670,800	8.34	19.03	0.91	815.56	843.26
500 MW E 3.5% sulfur	25	23,174,000	6.62	15.11	0.72	647.68	669.96
500 MW N 2.0% sulfur	30	17,091,700	4.88	11.39	0.54	1,055.04	1,097.73
500 MW N 3.5% sulfur	30	22,538,000	6.44	15.02	0.72	643.94	654.98
500 MW N 5.0% sulfur	30	27,513,400	7.86	18.34	0.87	507.81	528.60
1,000 MW E 3.5% sulfur	25	36,933,500	5.28	12.31	0.59	527.62	545.71
1,000 MW N 3.5% sulfur	30	35,602,400	5.09	12.28	0.58	526.12	544.21
90% SO_2 removal							
500 MW N 3.5% sulfur	30	23,812,400	6.80	15.87	0.76	598.30	617.70
Oil-Fired Power Unit							
0.8 lb SO_2/MBtu heat input allowable emission							
500 MW E 2.5% sulfur	25	16,091,700	4.60	3.02	0.50	1,042.88	1,060.76

a. Basis
Midwest plant location, 1980 revenue requirements.
Power unit on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Investment and revenue requirement for removal and disposal of fly ash excluded.

TABLE 38. LIMESTONE SLURRY PROCESS BASE CASE

ANNUAL REVENUE REQUIREMENTS DIRECT COSTS

	Total		Materials handling	Feed preparation	Gas handling	SO_2 absorption	Stack gas reheat	Solids disposal	Services, utilities, and miscellaneous	Pond construction	Total annual quantities	Total annual dollars	% of average annual revenue requirements
Total direct investment, $	26,000,000		1,759,000	1,740,000	4,318,000	8,918,000	1,282,000	1,658,000	1,180,000	5,145,000		26,000,000	
Total depreciable investment, $	46,677,000												
Total capital investment, $	48,728,000												
Direct Costs	Unit cost, $	Raw material											
Delivered raw materials													
Limestone	7.00/ton												
Annual quantity, tons		158,300									158,300		
Annual cost, $		1,108,100										1,108,100	7.86
Subtotal raw materials cost		1,108,100										1,108,100	7.86
Conversion costs													
Operating labor and supervision	12.50/man-hr												
Annual quantity, man-hr			4,200	6,600	1,690	8,500	1,500	3,500	-	-	25,990		
Annual cost, $			52,500	82,500	21,100	106,200	18,800	43,800	-	-		324,900	2.30
Utilities													
Steam	2.00/MBtu												
Annual quantity, MBtu			-	-	-	-	489,800	-	-	-	489,800		
Annual cost, $			-	-	-	-	979,600	-	-	-		979,600	6.95
Process water	0.12/kgal												
Annual quantity, kgal			-	-	-	247,400	-	-	-	-	247,400		
Annual cost, $			-	-	-	29,700	-	-	-	-		29,700	0.21
Electricity	0.029/kWh												
Annual quantity, kWh			770,000	4,458,000	26,179,000	24,171,000	-	637,000	455,000	-	56,670,000		
Annual cost, $			22,300	129,300	759,200	700,900	-	18,500	13,200	-		1,643,400	11.65
Maintenance (labor and material)													
Annual cost, $			140,700	139,200	345,500	713,400	102,600	132,600	94,400	154,400		1,822,800	12.93
Analyses	17.00/man-hr												
Annual quantity, man-hr		1,500	-	-	-	1,880	-	380	-	-	3,760		
Annual cost, $		25,500	-	-	-	32,000	-	6,400	-	-		63,900	0.45
Subtotal conversion costs		25,500	215,500	351,000	1,125,800	1,582,200	1,101,000	201,300	107,600	154,400		4,864,300	34.49
Total direct costs		1,133,600	215,500	351,000	1,125,800	1,582,200	1,101,000	201,300	107,600	154,400		5,972,400	42.35
Percent of total direct costs		18.98	3.61	5.88	18.85	26.49	18.43	3.37	1.80	2.59			

TABLE 39. GENERIC DOUBLE-ALKALI PROCESS BASE CASE

ANNUAL REVENUE REQUIREMENTS DIRECT COSTS

	Total		Materials handling	Feed preparation	Gas handling	SO_2 absorption	Stack gas reheat	Reaction	Solids separation	Solids disposal	Services, utilities, and miscellaneous	Pond construction	Total annual quantities	Total annual dollars	% of average annual revenue requirements
Total direct investment, $	26,750,000		1,710,000	833,000	4,268,000	9,206,000	1,282,000	357,000	2,352,000	1,247,000	1,274,000	4,261,000		26,750,000	
Total depreciable investment, $	48,530,000														
Total capital investment, $	50,551,000														
Direct Costs	Unit cost, $	Raw material													
Delivered raw materials															
Lime	42.00/ton														
Annual quantity, tons		63,600											63,600		
Annual cost, $		2,671,200												2,671,200	18.20
Soda ash	90.00/ton														
Annual quantity, tons		6,060											6,060		
Annual cost, $		545,400												545,400	3.72
Subtotal raw materials cost		3,216,600												3,216,600	21.92
Conversion costs															
Operating labor and supervision	12.50/man-hr														
Annual quantity, man-hr			4,200	6,600	1,700	7,000	1,500	1,750	8,250	3,500	-	-	34,500		
Annual cost, $			52,500	82,500	21,200	87,500	18,800	21,900	103,100	43,800	-	-		431,300	2.94
Utilities															
Steam	2.00/MBtu														
Annual quantity, MBtu			-	-	-	-	489,800	-	-	-	-	-	489,800		
Annual cost, $			-	-	-	-	979,600	-	-	-	-	-		979,600	6.67
Process water	0.12/kgal														
Annual quantity, kgal			121,800	-	-	46,620	-	-	44,100	28,980	-	-	241,500		
Annual cost, $			14,600	-	-	5,600	-	-	5,300	3,500	-	-		29,000	0.20
Electricity	0.029/kWh														
Annual quantity, kWh			1,078,000	903,000	17,872,000	5,369,000	-	819,000	2,100,000	504,000	455,000	-	29,100,000		
Annual cost, $			31,300	26,200	518,300	155,700	-	23,700	60,900	14,600	13,200	-		843,900	5.75
Maintenance (labor and material)															
Annual cost, $			68,400	33,300	169,900	368,200	51,300	14,300	94,100	49,900	51,000	127,200		1,027,600	7.00
Analyses	17.00/man-hr														
Annual quantity, hr		1,500	-	-	-	1,700	-	700	280	380	-	-	4,560		
Annual cost, $		25,500	-	-	-	28,900	-	11,900	4,700	6,500	-	-		77,500	0.53
Subtotal conversion costs		25,500	166,800	142,000	709,400	645,900	1,049,700	71,800	268,100	118,300	64,200	127,200		3,388,900	23.09
Total direct costs		3,242,100	166,800	142,000	709,400	645,900	1,049,700	71,800	268,100	118,300	64,200	127,200		6,605,500	45.01
Percent of total direct costs		49.08	2.52	2.15	10.74	9.78	15.89	1.09	4.06	1.79	0.97	1.93			

TABLE 40. CITRATE PROCESS BASE CASE

ANNUAL REVENUE REQUIREMENTS DIRECT COSTS

	Total		Materials handling	Feed preparation	Gas handling	SO_2 absorption	Stack gas reheat	Chloride purge	SO_2 reduction	Sulfur separation and removal	Sulfur storage and shipping
Total direct investment, $	36,847,000		770,000	132,000	4,093,000	12,285,000	1,282,000	97,000	1,100,000	2,706,000	772,000
Total depreciable investment, $	69,520,000										
Total capital investment, $	71,639,000										
Direct Costs	Unit cost, $	Raw material									
Delivered raw materials											
Lime	42.00/ton										
Annual quantity, tons		2,870									
Annual cost, $		120,500									
Soda ash	90.00/ton										
Annual quantity, tons		2,630									
Annual cost, $		236,700									
Citrate	1,340.00/ton										
Annual quantity, tons		230									
Annual cost, $		308,200									
Natural gas	3.50/kft^3										
Annual quantity, kft^3		1,050,000									
Annual cost, $		3,675,000									
Catalyst											
Annual quantity, tons		-									
Annual cost, $		21,000									
Subtotal raw materials cost		4,361,400									
Conversion costs											
Operating labor and supervision	12.50/man-hr										
Annual quantity, man-hr			2,000	1,750	1,700	7,000	1,500	1,750	9,240	9,240	3,500
Annual cost, $			25,000	21,900	21,200	87,500	18,700	21,900	115,500	115,500	43,800
Utilities											
Steam	2.00/MBtu										
Annual quantity, MBtu			-	-	-	-	489,800	-	-	180,700	68,600
Annual cost, $			-	-	-	-	979,600	-	-	361,400	137,200
Process water	0.06/kgal										
Annual quantity, kgal			-	-	-	197,400	-	-	-	400	-
Annual cost, $			-	-	-	11,900	-	-	-	-	-
Electricity	0.029/kWh										
Annual quantity, kWh			367,600	127,400	41,846,000	5,553,100	-	118,500	3,063,700	5,641,800	139,400
Annual cost, $			10,700	3,700	1,213,600	161,000	-	3,400	88,900	163,600	4,000
Maintenance (labor and material)											
Annual cost, $			46,200	7,900	245,600	737,100	76,900	5,800	66,000	162,400	46,300
Analyses	17.00/man-hr										
Annual quantity, man-hr		400	-	400	-	1,750	-	500	2,750	1,400	400
Annual cost, $		6,800	-	6,800	-	29,700	-	8,500	46,800	23,800	6,800
Subtotal conversion costs		6,800	81,900	40,300	1,480,400	1,027,200	1,075,200	39,600	317,200	826,700	238,100
Total direct costs		4,368,200	81,900	40,300	1,480,400	1,027,200	1,075,200	39,600	317,200	826,700	238,100
Percent of total direct costs		37.21	0.70	0.34	12.61	8.75	9.16	0.34	2.70	7.04	2.03

TABLE 40 (continued)

	Sulfate purge	H_2S generation	H_2 generation	Services, utilities, and miscellaneous	Byproduct sales revenue	Total annual quantities	Total annual dollars	% of average annual revenue requirements
Total direct investment, $	994,000	5,850,000	4,680,000	2,086,000				
Total depreciable investment, $								
Total capital investment, $							36,847,000	
Direct Costs								
Delivered raw materials								
Lime								
Annual quantity, tons						2,870		
Annual cost, $							120,500	0.53
Soda ash								
Annual quantity, tons						2,630		
Annual cost, $							236,700	1.05
Citrate								
Annual quantity, tons						230		
Annual cost, $							308,200	1.37
Natural gas								
Annual quantity, kft^3						1,050,000		
Annual cost, $							3,675,000	16.31
Catalyst								
Annual quantity, tons						-		
Annual cost, $							21,000	0.09
Subtotal raw materials cost							4,361,400	19.35
Conversion costs								
Operating labor and supervision								
Annual quantity, man-hr	9,240	14,000	7,000	-	-	67,920		
Annual cost, $	115,500	175,000	87,500	-	-		849,000	3.77
Utilities								
Steam								
Annual quantity, MBtu	-	121,000	175,800	-	-	1,035,900		
Annual cost, $	-	242,000	351,600	-	-		2,071,800	9.19
Process water								
Annual quantity, kgal	107,200	507,500	1,680,000	-	-	2,492,500		
Annual cost, $	6,400	30,500	100,800	-	-		149,600	0.66
Electricity								
Annual quantity, kWh	6,090,500	1,535,000	1,085,000	532,000	-	66,100,000		
Annual cost, $	176,600	44,500	31,500	15,400	-		1,916,900	8.51
Maintenance (labor and material)								
Annual cost, $	59,600	351,000	280,800	125,200	-		2,210,800	9.81
Analyses								
Annual quantity, man-hr	500	2,000	500	-		10,600		
Annual cost, $	8,500	34,000	8,500	-	-		180,200	0.80
Subtotal conversion costs	366,600	877,000	860,700	140,600			7,378,300	32.74
Total direct costs	366,600	877,000	860,700	140,600			11,739,700	52.09
Percent of total direct costs	3.12	7.47	7.33	1.20				

TABLE 41. LIMESTONE SLURRY PROCESS

ACTUAL AND DISCOUNTED CUMULATIVE TOTAL AND UNIT INCREASE (DECREASE) IN COST OF POWER OVER THE LIFE OF THE POWER UNIT[a]

Case	Years remaining life	Cumulative actual net increase (decrease) in cost of power, $	Lifetime average increase (decrease) in unit revenue requirement				Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit revenue requirement[c]			
			$/ton (bbl) of coal (oil) burned	Mills/kWh	$/MBtu heat input	$/ton of S removed		$/ton (bbl) of coal (oil) burned	Mills/kWh	$/MBtu heat input	$/ton of S removed
Coal-Fired Power Unit											
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)											
200 MW E 3.5% S	20	115,734,600	22.25	10.06	105.94	948.64	52,811,700	20.52	9.28	0.98	875.82
200 MW N 3.5% S	30	183,304,700	16.41	7.19	78.13	702.32	65,253,700	14.99	6.56	0.71	642.26
500 MW E 3.5% S	25	300,128,600	14.81	6.49	70.54	633.85	122,034,600	13.29	5.82	0.63	569.19
500 MW N 2.0% S	30	293,271,500	10.73	4.60	51.11	992.46	104,931,000	9.85	4.22	0.47	911.65
500 MW N 3.5% S	30	357,374,000	13.08	5.61	62.29	560.59	127,709,200	11.99	5.14	0.57	513.92
500 MW N 5.0% S	30	405,112,800	14.83	6.35	70.61	410.45	144,837,500	13.60	5.83	0.65	376.40
1,000 MW E 3.5% S	25	462,118,100	11.66	5.00	55.51	499.59	188,891,100	10.52	4.51	0.50	450.71
1,000 MW N 3.5% S	30	544,862,300	10.32	4.27	49.12	441.72	195,672,000	9.50	3.94	0.45	407.06
Solids disposal by trucking											
500 MW N 3.5% S	30	372,822,400	13.65	5.85	64.98	591.78	132,750,600	12.47	5.34	0.59	540.52
90% SO_2 removal; onsite solids disposal (ponding)											
500 MW N 3.5% S	30	371,004,000	13.58	5.82	64.66	497.66	132,602,400	12.45	5.34	0.59	456.62
Oil-Fired Power Unit											
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)											
500 MW E 2.5% S	25	231,792,200	3.29	5.01	54.48	1,182.61	94,271,900	2.96	4.50	0.49	1,062.82

a. Basis
Midwest plant location, 1980 revenue requirements.
Over previously defined unit operating profile. 30-yr life; 7,000 hr - 10 yr, 5,000 hr - 5 yr, 3,500 hr - 5 yr, 1,500 hr - 10 yr.
Stack gas reheat to 175°F.
Investment and revenue requirement for removal and disposal of fly ash excluded.
Limestone raw material cost, $7/ton.
Constant labor cost assumed over life of project.

b. Discounted at 10% to initial year.

c. Equivalent to discounted process cost over life of power units.

TABLE 42. GENERIC DOUBLE-ALKALI PROCESS

ACTUAL AND DISCOUNTED CUMULATIVE TOTAL AND UNIT INCREASE (DECREASE) IN COST OF POWER OVER THE LIFE OF THE POWER UNIT[a]

Case	Years remaining life	Cumulative actual net increase (decrease) in cost of power, $	Lifetime average increase (decrease) in unit revenue requirement				Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit revenue requirement[c]			
			$/ton (bbl) of coal (oil) burned	Mills/kWh	$/MBtu heat input	$/ton of S removed		$/ton (bbl) of coal (oil) burned	Mills/kWh	$/MBtu heat input	$/ton of S removed
Coal-Fired Power Unit											
1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)											
200 MW E 3.5% S	20	116,680,000	22.43	10.15	106.80	956.39	53,388,600	20.75	9.39	0.99	885.38
200 MW N 3.5% S	30	182,336,300	16.32	7.15	77.72	698.61	65,224,800	14.98	6.56	0.71	641.98
500 MW E 3.5% S	25	312,313,600	15.41	6.75	73.40	659.59	127,562,500	13.89	6.09	0.66	594.97
500 MW N 2.0% S	30	290,205,200	10.62	4.55	50.58	982.08	103,925,200	9.76	4.18	0.46	902.91
500 MW N 3.5% S	30	368,601,500	13.49	5.78	64.24	578.20	132,472,900	12.44	5.33	0.59	533.09
500 MW N 5.0% S	30	439,183,100	16.07	6.89	76.55	444.97	158,278,400	14.86	6.37	0.71	411.33
1,000 MW E 3.5% S	25	511,039,500	12.89	5.52	61.39	552.48	209,774,100	11.68	5.00	0.56	500.53
1,000 MW N 3.5% S	30	596,859,100	11.30	4.68	53.81	484.27	215,525,300	10.47	4.34	0.50	448.54
Solids disposal by trucking											
500 MW N 3.5% S	30	348,993,900	12.77	5.47	60.83	547.44	125,275,900	11.76	5.04	0.56	504.13
90% SO_2 removal; onsite solids disposal (ponding)											
500 MW N 3.5% S	30	386,333,300	14.14	6.06	67.33	533.24	138,947,500	13.05	5.59	0.62	491.85
Oil-Fired Power Unit											
0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal (ponding)											
500 MW E 2.5% S	25	228,580,000	3.25	4.94	53.72	1,166.22	93,023,600	2.92	4.44	0.48	1,048.74

a. Basis

Midwest plant location, 1980 revenue requirements.

Over previously defined unit operating profile. 30-yr life; 7,000 hr - 10 yr, 5,000 hr - 5 yr, 3,500 hr - 5 yr, 1,500 hr - 10 yr.

Stack gas reheat to 175°F.

Investment and revenue requirement for removal and disposal of fly ash excluded.

Constant labor cost assumed over life of project.

b. Discounted at 10% to initial year.

c. Equivalent to discounted process cost over life of power units.

TABLE 43. CITRATE PROCESS

ACTUAL AND DISCOUNTED CUMULATIVE TOTAL AND UNIT INCREASE (DECREASE) IN COST OF POWER OVER THE LIFE OF THE POWER UNIT[a]

Case	Years remaining life	Cumulative actual net increase (decrease) in cost of power, $	Lifetime average increase (decrease) in unit revenue requirement				Cumulative present worth net increase (decrease) in cost of power,[b] $	Levelized increase (decrease) in unit revenue requirement[c]			
			$/ton (bbl) of coal (oil) burned	Mills/kWh	$/MBtu heat input	$/ton of S removed		$/ton (bbl) of coal (oil) burned	Mills/kWh	$/MBtu heat input	$/ton of S removed
Coal-Fired Power Unit											
1.2 lb SO_2/MBtu heat input allowable emission											
200 MW E 3.5% S	20	185,604,300	35.68	16.14	169.89	1,521.35	84,862,500	32.98	14.92	1.57	1,407.34
200 MW N 3.5% S	30	292,291,500	26.17	11.46	124.59	1,119.89	104,508,300	24.00	10.51	1.14	1,028.63
500 MW E 3.5% S	25	457,099,200	22.56	9.88	107.43	965.36	187,099,800	20.38	8.93	0.97	872.67
500 MW N 2.0% S	30	429,700,300	15.73	6.74	74.89	1,454.15	153,984,800	14.46	6.20	0.69	1,337.83
500 MW N 3.5% S	30	557,059,800	20.39	8.74	97.09	873.82	200,363,000	18.81	8.06	0.90	806.29
500 MW N 5.0% S	30	670,722,600	24.55	10.52	116.90	679.56	241,941,500	22.72	9.74	1.08	628.75
1,000 MW E 3.5% S	25	711,393,300	17.94	7.69	85.45	769.07	293,113,800	16.32	6.99	0.78	699.39
1,000 MW N 3.5% S	30	863,634,100	16.35	6.77	77.86	700.72	312,517,300	15.18	6.29	0.72	650.40
90% SO_2 removal											
500 MW N 3.5% S	30	586,326,400	21.46	9.20	102.19	808.73	211,103,800	19.82	8.50	0.94	747.01
Oil-Fired Power Unit											
0.8 lb SO_2/MBtu heat input allowable emission											
500 MW E 2.5% S	25	322,358,300	4.58	6.97	75.76	1,584.07	131,410,200	4.12	6.27	0.68	1,425.27

a. Basis
Midwest plant location, 1980 revenue requirements.
Over previously defined unit operating profile. 30-yr life; 7,000 hr - 10 yr, 5,000 hr - 5 yr, 3,500 hr - 5 yr, 1,500 hr - 10 yr.
Stack gas reheat to 175°F.
Investment and revenue requirement for removal and disposal of fly ash excluded.
Revenue $40/short ton S.
Constant labor cost assumed over life of project.

b. Discounted at 10% to initial year.

c. Equivalent to discounted process cost over life of power units.

Discussion of Results

Annual Revenue Requirements--

Summaries of the case variations for each process are shown in the appendix and tabulated totals are presented in Tables 35-37. In comparing results, it should be remembered that limestone and double alkali are waste-producing processes and citrate is a recovery process; however, credit for the sale of sulfur is included in the annual revenue requirements projected for citrate.

Generally, the ranking of annual revenue requirements for the processes is the same as the capital investment rankings. Projected revenue requirements for the limestone slurry process range from \$7,153,200 (5.11 mills/kWh) for a new 200-MW 3.5% sulfur coal-fired unit to \$23,241,200 (3.32 mills/kWh) for an existing 1,000-MW 3.5% sulfur coal-fired unit. Annual revenue requirements for the generic double-alkali process range from \$7,169,100 (5.12 mills/kWh) for a new 200-MW 3.5% sulfur coal-fired unit to \$25,750,900 (3.68 mills/kWh) for an existing 1,000-MW 3.5% sulfur coal-fired unit.

The sulfur-producing citrate process has greater annual revenue requirements than the waste-producing processes. The projected annual revenue requirements for citrate range from \$11,670,800 (8.34 mills/kWh) for a new 200-MW 3.5% sulfur coal-fired unit to \$36,933,500 (5.28 mills/kWh) for an existing 1,000-MW 3.5% sulfur coal-fired unit.

The sensitivity of revenue requirements to variations in the more important economic parameters has been evaluated and the effects of these variations on the projected annual revenue requirements are presented in Figures 20-36. Table 44 identifies the parameters that are varied and the range of values that is studied. Each range has been selected to correspond to differences in design or costs which might be encountered in more site-specific operation. As an illustration, limestone price variations represent the effect of plant location and the corresponding effect on overall process costs. Operating labor price fluctuations might also be the result of plant location.

Figures 20-22 show the effects of power unit size and status (new and existing) and sulfur content of coal on annual revenue requirements. As the projections show, sulfur in coal has a greater effect on the citrate process, while the differences in status of power units have a small effect on the annual revenue requirements of a specific unit size.

Special case variations are shown for the alternate disposal of waste solids by trucking and 90% SO_2 removal. Tables 45 and 46 display the results of these projections.

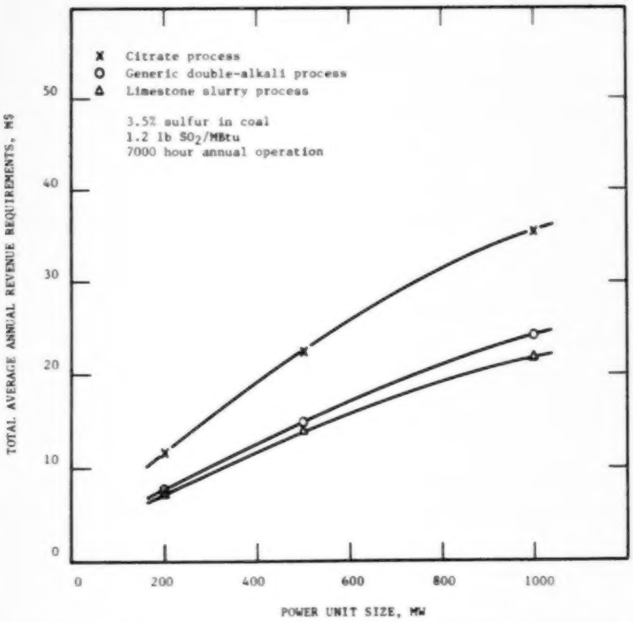

Figure 20. All processes. Effect of power unit size on annual revenue requirements for new coal-fired units.

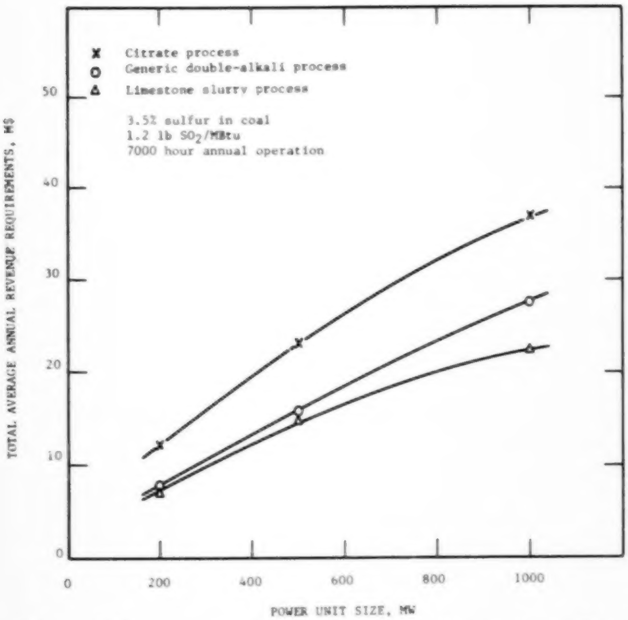

Figure 21. All processes. Effect of power unit size on annual revenue requirements for existing coal-fired units.

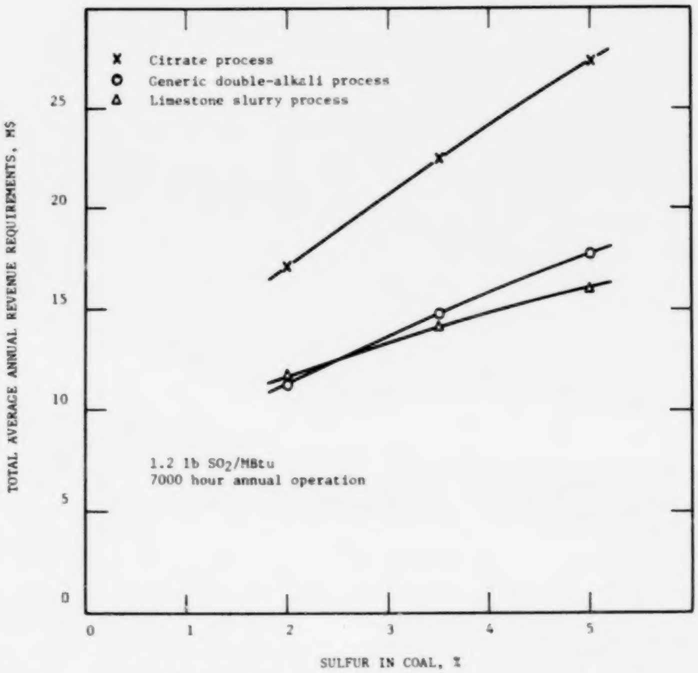

Figure 22. All processes. Effect of sulfur content of coal on annual revenue requirements for new 500-MW units.

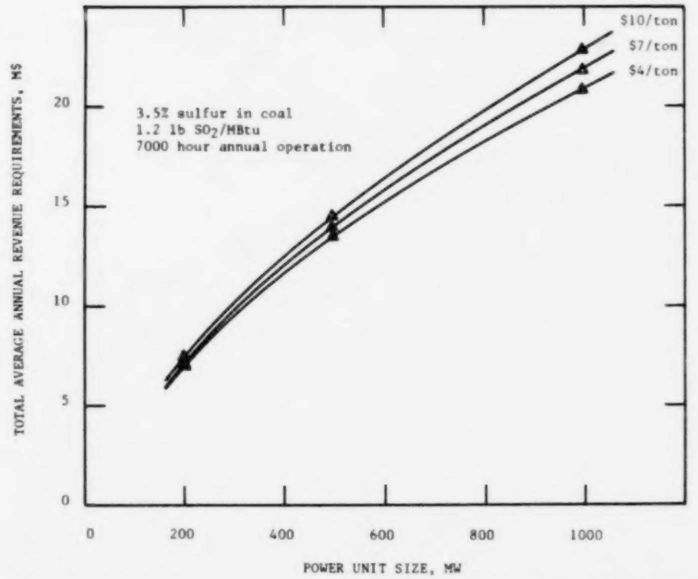

Figure 23. Limestone slurry process. Effect of power unit size and variations in limestone price on annual revenue requirements for new coal-fired units.

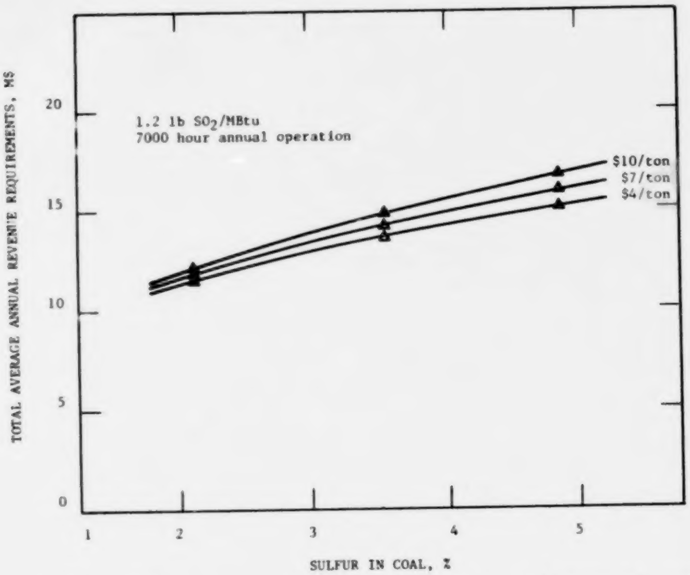

Figure 24. Limestone slurry process. Effect of sulfur in coal and variations in limestone price on annual revenue requirements for new 500-MW units.

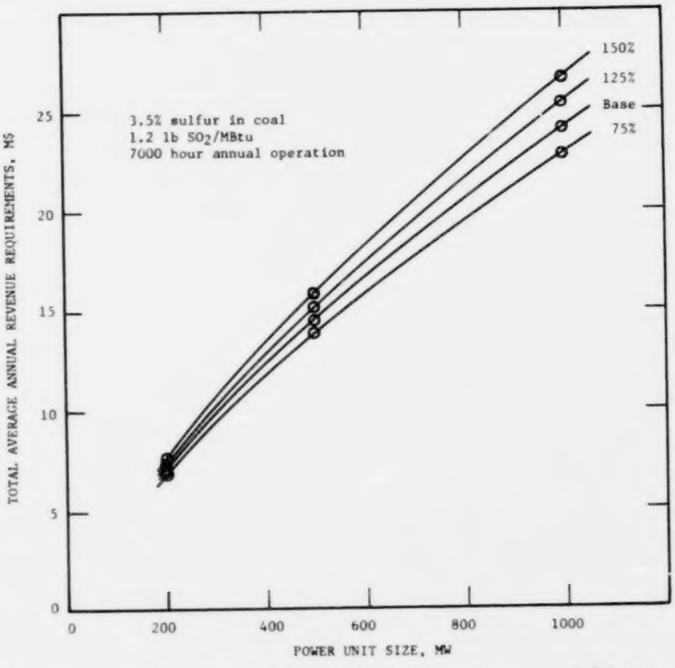

Figure 25. Generic double-alkali process. Effect of power unit size and variations in total raw materials cost on annual revenue requirements for new coal-fired units.

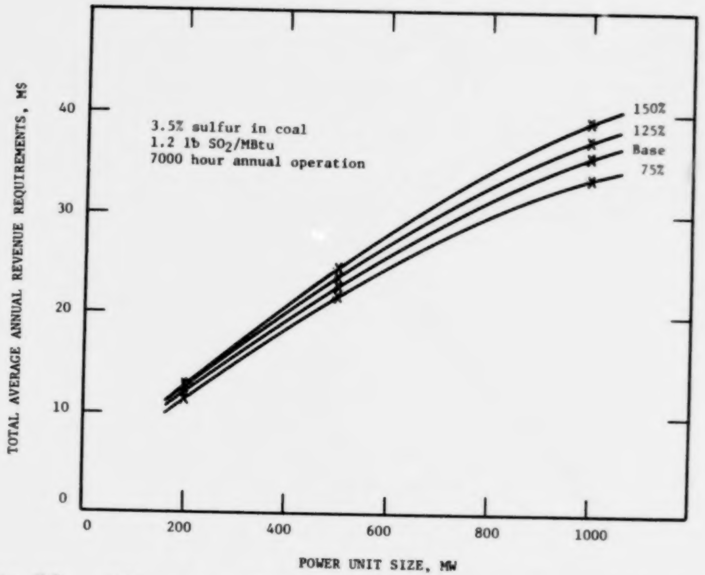

Figure 26. Citrate process. Effect of power unit size and variations in total raw materials cost on annual revenue requirements for new coal-fired units.

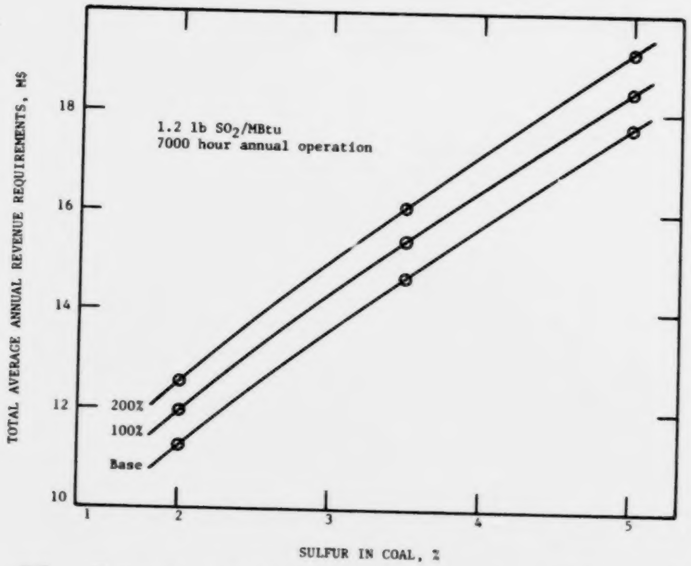

Figure 27. Generic double-alkali process. Effect of sulfur in coal and variations in operating labor cost on annual revenue requirements for new 500-MW units.

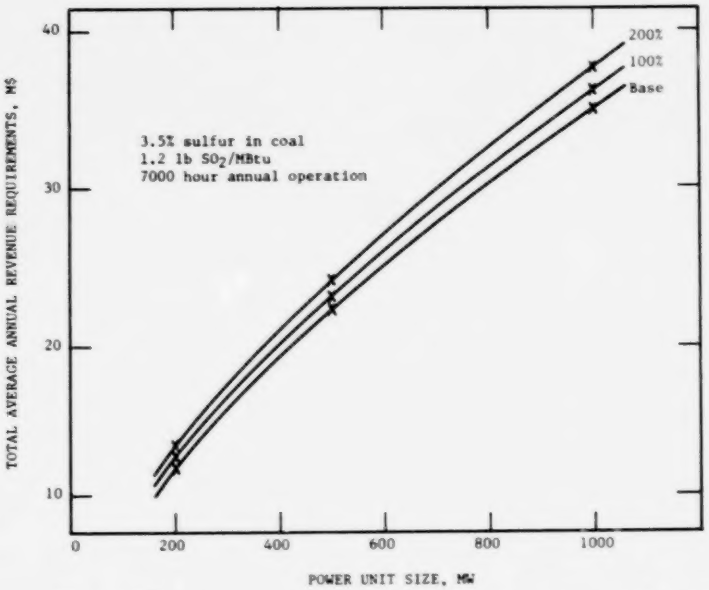

Figure 28. Citrate process. Effect of power unit size and variations in operating labor cost on annual revenue requirements for new coal-fired units.

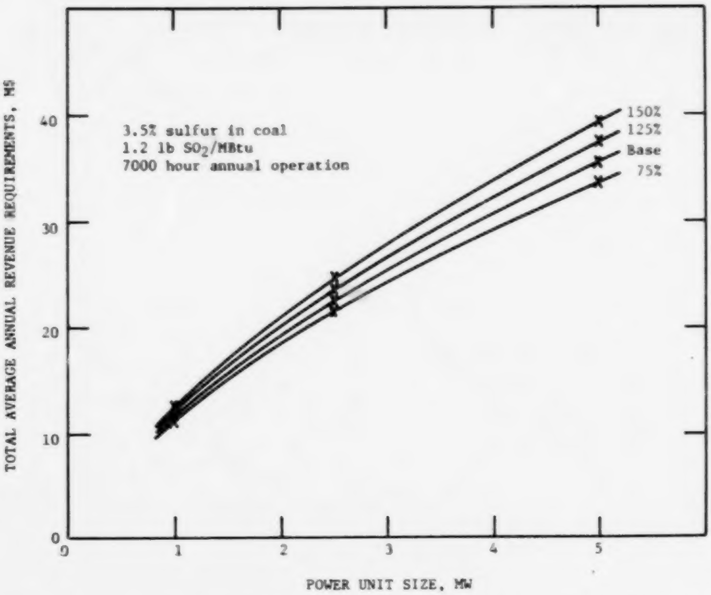

Figure 29. Citrate process. Effect of power unit size and variations in energy cost on annual revenue requirements for new coal-fired units.

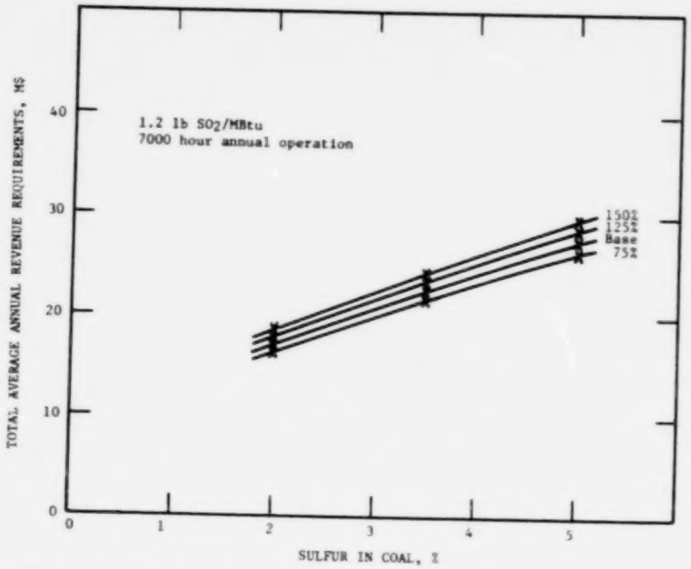

Figure 30. Citrate process. Effect of sulfur in coal and variations in energy cost on annual revenue requirements for new 500-MW units.

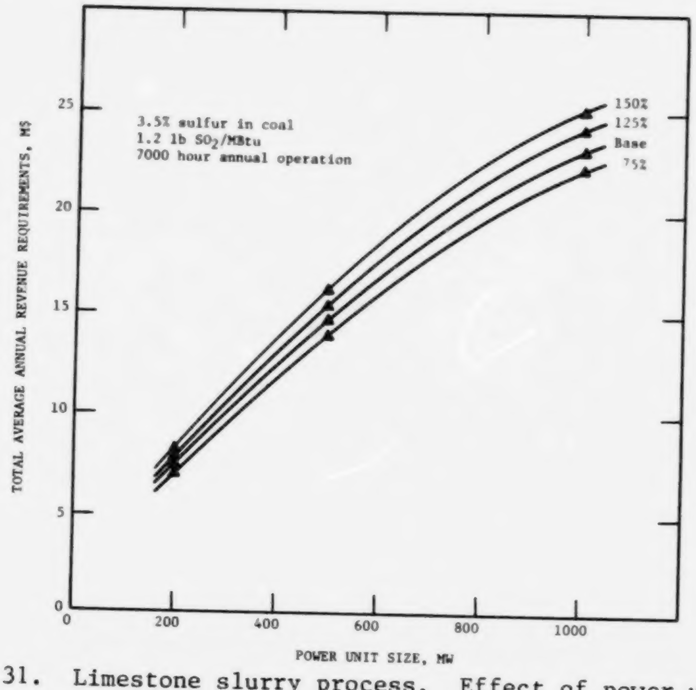

Figure 31. Limestone slurry process. Effect of power unit size and variations in maintenance cost on annual revenue requirements for new coal-fired units.

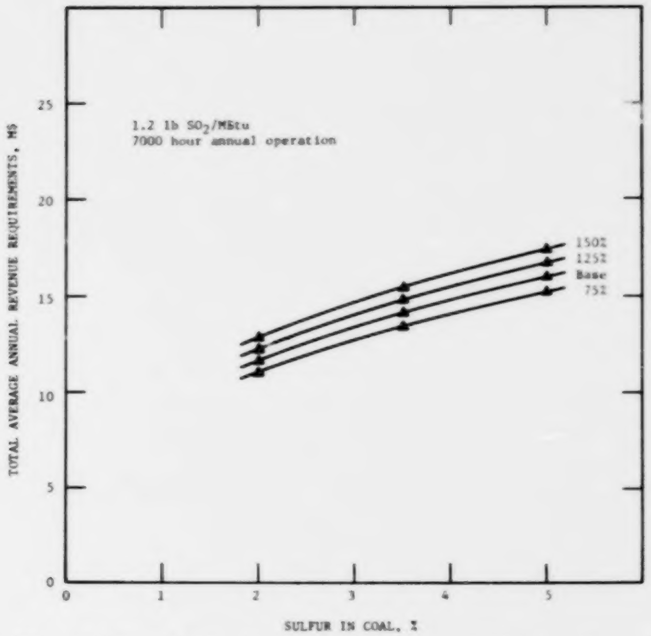

Figure 32. Limestone slurry process. Effect of sulfur in coal and variations in maintenance cost on annual revenue requirements for new 500-MW units.

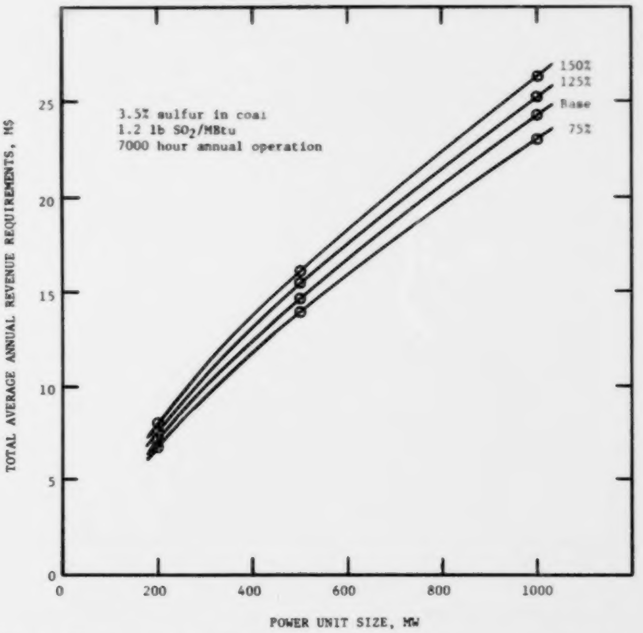

Figure 33. Generic double-alkali process. Effect of power unit size and variations in capital charges on annual revenue requirements for new coal-fired units.

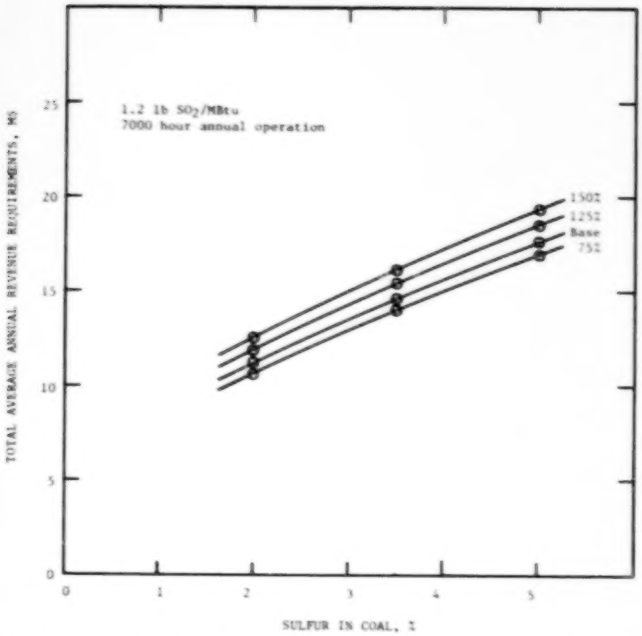

Figure 34. Generic double-alkali process. Effect of sulfur in coal and variations in capital charges on annual revenue requirements for new 500-MW units.

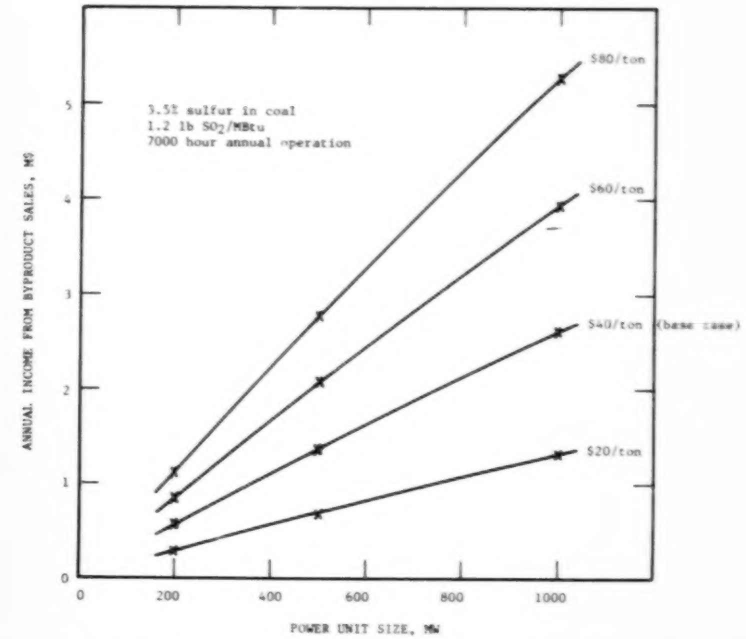

Figure 35. Citrate process. Effect of power unit size and variations in sulfur price on total annual income from byproduct sales for new coal-fired units.

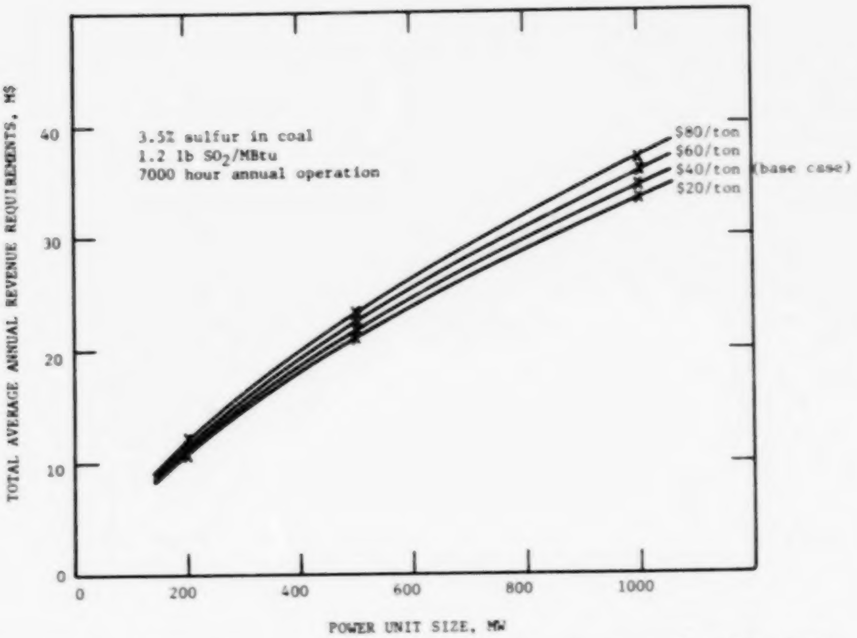

Figure 36. Citrate process. Effect of power unit size and variations in sulfur price on annual revenue requirements for new coal-fired units.

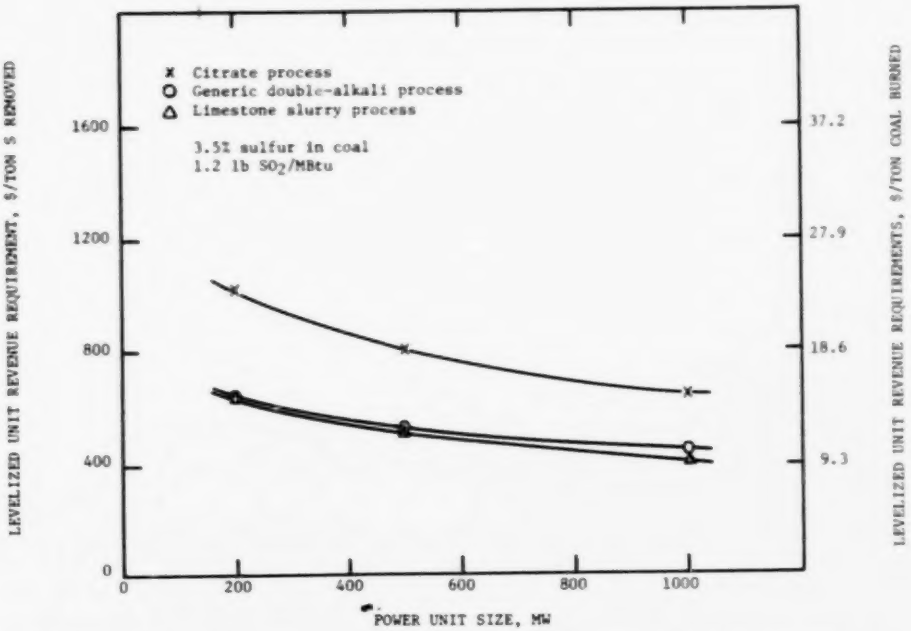

Figure 37. All processes. Effect of power unit size on levelized unit revenue requirements for new coal-fired units.

TABLE 44. SENSITIVITY VARIATIONS STUDIED IN THE ECONOMIC COST PROJECTIONS

Item	Process	Power unit description[a]	Annual revenue requirements	
			Base value	Range of variations
Raw material price	Limestone	1 and 2	Limestone, \$7/ton	\$4-\$10/ton
	Double alkali	1	Lime, \$42/ton Soda ash, \$90/ton	75-150% of total raw material cost
	Citrate	1	Lime, \$42/ton Soda ash, \$90/ton Citric acid, \$0.67/ton Natural gas, \$3.50/kft^3	75-150% of total raw material cost
Operating labor	Double alkali	2	Labor, \$12.50/man-hr	\$12.50-\$25.00/man-hr
	Citrate	1	Labor, \$12.50/man-hr	\$12.50-\$25.00/man-hr
Energy cost	Citrate process	1	Steam, \$2.00/MBtu Electricity, \$0.029/kWh	
Maintenance	Limestone	1 and 2	8% of direct investment excluding pond construction plus 3% of pond construction	50-150%
Capital charges	Double alkali	1 and 2	Average capital charges, 6.0% of total depreciable investment plus 8.6% of total capital investment	
Product revenue	Citrate	1	Sulfur, \$40/ton	\$20-\$80/ton

[a] Power unit description

1. New power units: 200, 500, and 1,000 MW; 3.5% sulfur in coal.
2. New power unit, 500 MW: 2.0%, 3.5%, and 5.0% sulfur in coal.

TABLE 45. COMPARISON OF AVERAGE ANNUAL REVENUE REQUIREMENTS FOR SOLIDS DISPOSAL ALTERNATIVES[a]

Process	Slurry ponding (base case), $	Filter cake trucking, $	Revenue requirement increase (decrease) in trucking alternative	
			$	%
Limestone	14,101,900	15,172,400	1,070,500	7.6
Double alkali	14,676,000	14,293,900	(382,100)	(2.6)

a. Base case conditions: Pond and cake disposal areas each 1 mile from scrubbing facilities.

TABLE 46. COMPARISON OF AVERAGE ANNUAL REVENUE REQUIREMENTS FOR DIFFERENT SO_2 REMOVAL LEVELS

	Projected total annual (7,000 hr) revenue requirements, $ (500-MW new 3.5% sulfur coal-fired units)		Annual revenue requirement increase resulting from increased SO_2 removal	
Process	1.2 lb SO_2/MBtu heat input allowable emission	90% SO_2 removal	$	%
Limestone	14,101,900	14,651,300	549,400	3.9
Double alkali	14,676,000	15,438,800	762,800	5.2
Citrate	22,538,000	23,812,400	1,274,400	5.7

The trucking alternative for limestone increases annual revenue requirements by 7.6% over the limestone base case, a result of additional operating labor, analyses, electricity, and fuel. While operating labor for trucking and fuel charges are added to the cost of double alkali, the original operating labor and electricity needs are decreased because the filter cake is not reslurried and pumped to disposal. In addition, the indirect cost decreases by $957,000, resulting in an overall decrease in revenue requirements. The double-alkali trucking alternative revenue requirements are 6% less than limestone trucking but are still higher than the limestone slurry ponding case by approximately 1.4%.

Removal of 90% of the SO_2 compared with removal to meet emission standards results in revenue requirement increases of 4% to 6% for new 500-MW units. The credit for additional sulfur recovered and sold in the citrate process does not equal the increases in raw materials and utilities necessary for the additional removal.

From the detailed area-by-area base case annual revenue requirement breakdown analyses (shown in Tables 38-40) it can be seen that total capital charges are the largest components of revenue requirement for each process. Base case capital charges range from 46% of total annual revenue requirements in the citrate process to 50% in limestone and double-alkali processes. As would be expected because of the complexity of the process, citrate has the highest process operating labor cost. When disposal equipment operation is included (trucking alternative cases), however, labor costs for limestone are the highest. Excluding the trucking case variations, operating labor ranges from 2% to 6% of the total revenue requirements for all processes. Energy costs are significant for all processes. Steam for reheat is approximately the same for all processes, but citrate requires additional steam for product sulfur. Table 47 shows the four major operating cost components of each process and the corresponding percentage distribution of annual revenue requirements attributed to each component for the base case installation.

TABLE 47. MAJOR OPERATING COST COMPONENTS INCLUDED

IN THE BASE CASE ANNUAL REVENUE REQUIREMENTS

	Major operating cost components (percent of annual revenue requirements)			
Process	1	2	3	4
Limestone	Capital charges (49.58)	Maintenance (12.93)	Electricity (11.65)	Limestone (7.86)
Double alkali	Capital charges (49.47)	Raw materials (21.92)	Maintenance (7.00)	Steam (6.67)
Citrate	Capital charges (45.84)	Raw materials (19.35)	Maintenance (9.81)	Steam (9.19)

The sensitivity of the annual revenue requirements to variations in raw material price for the limestone process is shown in Figures 23-26. Figures 27 and 28 show the sensitivity of annual revenue requirements to variations in operating labor costs for the generic double-alkali process. Although similar variations in operating labor projections for limestone result in different ranges of costs, the general effect is similar.

The effect of energy cost variations for the citrate process is shown in Figures 29 and 30 for variations in power unit sizes and sulfur levels in coal. The effect of varying energy is similar for the other processes.

Maintenance is one of the major operating cost components of annual revenue requirements for all three processes. Figures 31 and 32 project the effect of varying maintenance requirements for the limestone slurry process.

Table 47 shows that capital charges have the greatest effect on annual revenue requirements. For the double-alkali process the effect of capital charge variations as a function of power unit size and sulfur level is shown in Figures 33 and 34.

Annual income from the sale of sulfur for the citrate process will vary according to Figure 35 as a function of power unit size and selling prices. The effect of variations in selling price on annual revenue requirements is presented in Figure 36.

Lifetime Revenue Requirements--

Along with the investment and annual revenue requirement summary tables given in the appendix, computer projections of the detailed year-to-year operating cost and sales revenue analyses for all case variations for each of the three processes are presented. These projections are prepared on a regulated economics basis as discussed in the procedure and correspond to the 30-year declining operating profile of the unit established in the power plant premises. Annual capital charges are based on the undepreciated investment. The overall net increase or decrease in cost of power is shown for each year, considering the declining annual operating cost and the net sales revenue resulting from sale of sulfur. Lifetime costs, both total and discounted (at the regulated cost of money - 11.6% for this study), are displayed and equivalent unit revenue requirements are shown. Summarized results of the lifetime revenue requirement projections for the three processes are presented in Tables 41-43. Table 48 shows the cumulative lifetime credits, both actual and discounted, for the citrate process which are included in the lifetime cost projections. Cumulative lifetime costs for the solids disposal alternatives and for different SO_2 removal levels are compared in Tables 49 and 50.

Graphic representations of the effect of power unit size on levelized unit revenue requirement in dollars per ton of sulfur removed for new and existing coal-fired power units are shown in Figures 37 and 38. These unit cost results show trends similar to the annual revenue requirement estimates; however, the magnitude of the costs is greater. The higher costs are the result of the declining operating profile of the power plant.

TABLE 48. CITRATE PROCESS

LIFETIME SULFUR PRODUCTION AND CREDIT

Case	Years remaining life	Lifetime production sulfur, short tons	Net revenue, $/short ton sulfur	Cumulative revenue Actual, $	Cumulative revenue Discounted, $
Coal-Fired Power Unit					
1.2 lb SO_2/MBtu heat input allowable emission					
200 MW E 3.5% sulfur	20	117,500	40.00	4,700,000	2,320,500
200 MW N 3.5% sulfur	30	252,000	40.00	10,080,000	3,922,200
500 MW E 3.5% sulfur	25	457,000	40.00	18,280,000	8,285,300
500 MW N 2.0% sulfur	30	283,500	40.00	11,340,000	4,427,100
500 MW N 3.5% sulfur	30	627,000	40.00	25,080,000	9,771,300
500 MW N 5.0% sulfur	30	949,000	40.00	37,960,000	14,794,700
1,000 MW E 3.5% sulfur	25	894,000	40.00	35,760,000	16,207,400
1,000 MW N 3.5% sulfur	30	1,191,000	40.00	47,640,000	18,571,800
90% SO_2 removal					
500 MW N 3.5% sulfur	30	702,000	40.00	28,080,000	10,936,300
Oil-Fired Power Unit					
0.8 lb SO_2/MBtu heat input allowable emission					
500 MW E 2.5% sulfur	25	201,000	40.00	8,040,000	3,637,700

TABLE 49. COMPARISON OF CUMULATIVE LIFETIME DISCOUNTED PROCESS COST FOR SOLIDS DISPOSAL ALTERNATIVES[a]

Process	Cumulative discounted process cost: Slurry ponding (base case), $	Cumulative discounted process cost: Filter cake trucking, $	Cumulative discounted lifetime increase (decrease) resulting from trucking alternative: $	Cumulative discounted lifetime increase (decrease) resulting from trucking alternative: %
Limestone	127,709,200	132,750,600	5,041,400	3.9
Double alkali	132,472,900	125,275,900	(7,197,000)	(5.4)

a. Base case conditions: Pond and cake disposal areas each 1 mile from scrubbing facilities.

TABLE 50. COMPARISON OF CUMULATIVE LIFETIME DISCOUNTED PROCESS COSTS FOR DIFFERENT SO_2 REMOVAL LEVELS

Process	Cumulative lifetime discounted process cost, $ (500-MW, new, 3.5% sulfur coal-fired units): 1.2 lb SO_2/MBtu heat input allowable emission	Cumulative lifetime discounted process cost, $ (500-MW, new, 3.5% sulfur coal-fired units): 90% SO_2 removal	Cumulative lifetime discounted cost increase resulting from increased SO_2 removal to 90%: $	Cumulative lifetime discounted cost increase resulting from increased SO_2 removal to 90%: %
Limestone	127,709,200	132,602,400	4,893,200	3.8
Double alkali	132,472,900	138,947,500	6,474,600	4.9
Citrate	200,363,000	211,103,800	10,740,800	5.4

Figure 39 shows the effect of sulfur content of coal on levelized lifetime unit revenue requirements ($/ton of sulfur removed) for a new 500-MW unit. In comparison with the annual revenue requirements given earlier, the relative ranking remains the same.

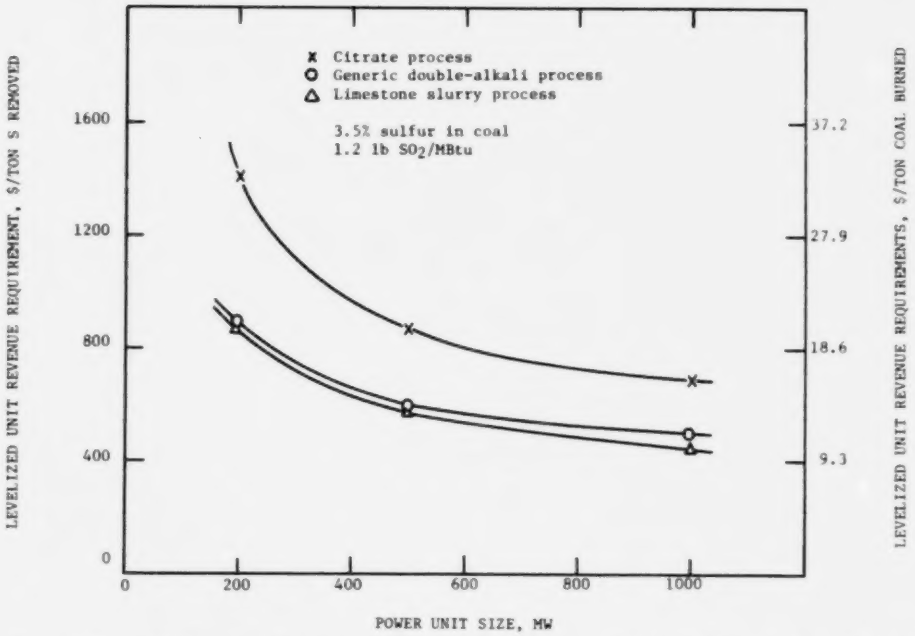

Figure 38. All processes. Effect of power unit size on levelized unit revenue requirements for existing coal-fired units.

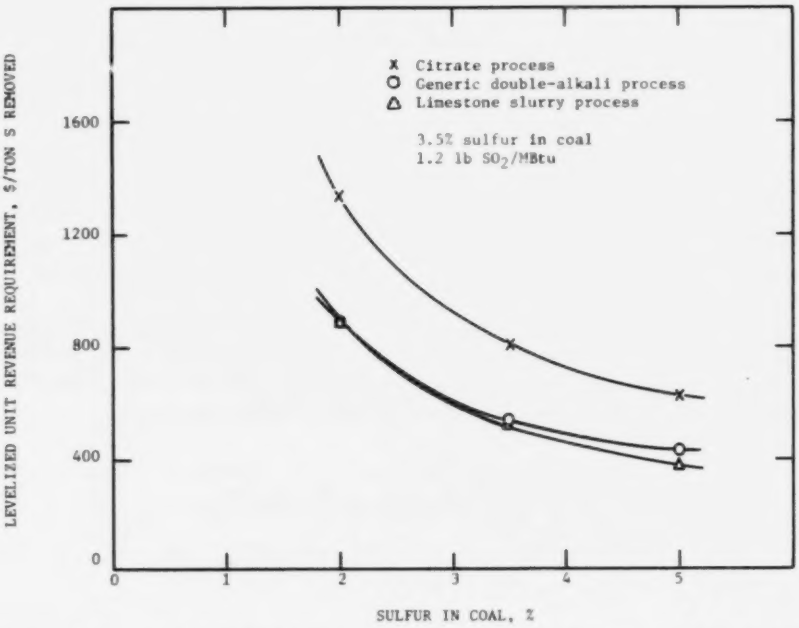

Figure 39. All processes. Effect of sulfur in coal on levelized unit revenue requirements for new 500-MW units.

CONCLUSIONS

The conclusions of this study have been summarized for capital investment requirements, revenue requirements, and processes. These are listed below.

CAPITAL INVESTMENT CONCLUSIONS

1. For base case conditions, the limestone process has the lowest investment requirements, followed by the double-alkali process, with the citrate process the highest. This ranking remains the same for each case variation except for the disposal-by-trucking alternative in which the limestone case variation investment is 2.4% higher than the double-alkali case. Limestone FGD requires more waste solids handling and a more expensive feed preparation area resulting in slightly higher capital investment needs. When the double-alkali disposal-by-trucking case is compared with the limestone base case (slurry disposal by ponding) limestone capital investment is 18% higher. It should be recognized that citrate is a recovery process and should also be compared with other recovery processes.

2. With one exception, the existing power unit case variations are greater than the new power unit case variations at each power plant size (200, 500, or 1,000 MW) in each process. In the limestone 200-MW cases, the decrease in costs because of the decrease in pond size based on a remaining life of 20 years is greater than the increase in labor charges required for retrofit situations so that the capital investment for the 200-MW existing unit is lower than the 200-MW new unit investment. Plant age is an important factor in the limestone and double-alkali waste-producing processes where pond size depends on remaining plant life.

3. Capital investment requirements are greater for systems that are designed for higher sulfur content. The existing oil-fired variation (2.5% sulfur in oil), however, requires less capital investment than the existing 500-MW unit burning 2.0% sulfur coal.

4. Removal of 90% of the SO_2 (instead of the removal to meet emission standards) increases investment by 3.5% to 4%.

5. Special purging of chlorides is unnecessary in waste-producing processes where enough neutralized chloride is trapped in the interstitial water in the settled sludge to maintain chloride control. Processes producing salable products, such as the citrate process, must control chloride buildup in the system. However, the addition of a chloride purge accounts for less than 1% of the direct investment.

6. In each process the SO_2 absorption area has greatest effect on the investment cost, from 29% to 43% of the direct investment. Gas handling and pond construction also contribute significantly to the direct investment. In the citrate process the H_2 and H_2S generation plants represent 22% to 33% of the direct investment.

REVENUE REQUIREMENT CONCLUSIONS

1. For base case conditions, the limestone process has the lowest annual revenue requirements, followed by the double-alkali process, with the citrate process the highest. This ranking remains the same for each case variation except for three instances: (1) 500-MW, 2% sulfur in coal, (2) 500-MW, 3.5% sulfur in coal with disposal-by-trucking, and (3) 500-MW, 2.5% sulfur in oil. For these variations, double-alkali annual revenue requirements are lower than limestone. In the limestone 500-MW, 2.0% sulfur in coal variation, electricity and maintenance costs are great enough to increase annual revenue requirements 3% over the comparable double-alkali requirements. (Base case limestone annual revenue requirements are 4% less than comparable double-alkali annual revenue requirements and 40% less than comparable citrate annual revenue requirements.) In the trucking and oil variations, electricity and maintenance charges increase limestone annual revenue requirements 6% and 3%, respectively, over those of double alkali. Also contributing to the increase in limestone annual revenue requirements over those of double alkali in the trucking variation are additional vehicle fuel costs and a plant overhead charge that is $500,000 greater in limestone. Lifetime revenue requirements follow a similar pattern.

2. Annual revenue requirements for the existing power unit variations are greater than the new power unit costs at each power plant size in each process. The increases in annual revenue requirements range from 3% at the 500-MW size for citrate to 7% at the 1,000-MW size for double alkali.

3. Annual revenue requirements are greater for systems which are designed for higher sulfur content. As with capital investment requirements, the oil variation (existing 500-MW unit, 2.5% sulfur) requires less revenue than the existing 500-MW unit burning 2.0% sulfur coal, but there is no direct comparison between the two.

4. Removal of 90% of the SO_2 (instead of removal to meet 1.2 lb/MBtu emission standards) increases revenue requirement by 4% to 6%. The credit for additional sulfur removed and sold in the citrate process does not equal the increases in raw material and utility costs required for the additional removal.

5. Raw material costs are highest for the citrate process and lowest for the limestone process. Natural gas is the largest raw material cost in the citrate process, representing approximately 85% of the total raw material cost. The lime required for chloride neutralization in the citrate process adds from $49,100 to $240,700 to the raw material costs in the case variations evaluated.

6. As would be expected because of the complexity of the process, citrate has the highest total process operating labor cost. When disposal equipment operation is included (trucking alternative cases), however, labor costs for limestone are the highest. Excluding the trucking case variations, operating labor ranges from 2% to 6% of the annual revenue requirements for all processes.

7. Energy costs are significant for all processes. Double alkali has the lowest electricity requirement; citrate requires additional steam for product sulfur. Steam for reheat is essentially the same for all processes.

8. Maintenance ranges from 5% of the annual revenue requirements for the double-alkali 1,000-MW existing unit to 15% for the limestone 200-MW existing unit.

9. Capital charges are the largest component of revenue requirement for each process. Base case capital charges range from 50% of annual revenue requirements in limestone and double-alkali processes to 46% in the citrate process.

10. Revenue from the sale of sulfur produced in the citrate process amounts to 4% to 8% of the adjusted revenue requirement.

PROCESS CONCLUSIONS

The limestone-lime slurry process is the best known and most completely developed FGD system in the United States today. The evaluation of limestone FGD in this study reflects the broad experience of vendors and utilities in constructing and operating this system. Limestone is still the simplest and cheapest FGD process available today for most applications, but it continues to require intensive maintenance effort, it is a once-through process, and it produces a throwaway sludge of questionable stability and environmental effects.

While construction and operating experience is not as extensive for double alkali as for limestone, double-alkali FGD is a competitive alternative to limestone, especially when trucking is used to dispose of the waste. While double alkali is a waste-producing process, it requires less area for disposal and it regenerates the process scrubbing liquor. Because of system design, it should require less maintenance than limestone. As more experience is gained in constructing and operating the system, capital investment and revenue requirements could decrease because of changes in process design, but no significant changes are anticipated.

As a recovery system, the citrate process is inherently more expensive and cannot be compared directly with the throwaway processes evaluated here. For this study the citrate process is assumed proven. However, less is known about the integrated technology for this system than is known about limestone or double alkali, and the operation of many of the process areas is more complex. The citrate process is a more environmentally acceptable process than either the limestone or double-alkali processes because the disadvantage of producing waste solids is eliminated by the production of sulfur and sodium sulfate. Maintenance may also be relatively simple. More extensive engineering and operating experience could decrease costs in the areas of reduction and sulfur separation. However, the use of natural gas in the reduction step presents possible future problems of supply. The citrate process must be proven in the field in order to answer questions of real cost and operability.

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APPENDIX A

TOTAL CAPITAL INVESTMENT, AVERAGE ANNUAL REVENUE REQUIREMENT, AND LIFETIME REVENUE REQUIREMENT TABLES - ALL PROCESSES AND CASE VARIATIONS

TABLE A-1. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(200-MW existing coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	1,070,000	8.3
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,208,000	9.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	2,203,000	17.2
SO_2 absorption (two TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	4,310,000	33.6
Stack gas reheat (two indirect steam reheaters)	584,000	4.5
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,392,000	10.8
Subtotal	10,767,000	83.8
Services, utilities, and miscellaneous	646,000	5.0
Total process areas excluding pond construction	11,413,000	88.8
Pond construction	1,444,000	11.2
Total direct investment	12,857,000	100.0
Indirect Investment		
Engineering design and supervision	869,000	6.8
Architect and engineering contractor	203,000	1.6
Construction expense	2,062,000	16.0
Contractor fees	669,000	5.2
Total indirect investment	3,803,000	29.6
Contingency	3,332,000	25.9
Total fixed investment	19,992,000	155.5
Other Capital Charges		
Allowance for startup and modifications	1,855,000	14.4
Interest during construction	2,399,000	18.7
Total depreciable investment	24,246,000	188.6
Land	295,000	2.3
Working capital	516,000	4.0
Total capital investment	25,057,000	194.9

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-2. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(200-MW existing coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	67,700 tons	7.00/ton	473,900	6.34
Total raw materials cost			473,900	6.34
Conversion costs				
Operating labor and supervision	16,440 man-hr	12.50/man-hr	205,500	2.75
Utilities				
Steam	206,800 MBtu	2.00/MBtu	413,600	5.53
Process water	107,100 kgal	0.12/kgal	12,900	0.17
Electricity	23,927,000 kWh	0.031/kWh	741,700	9.92
Maintenance				
Labor and material			1,070,500	14.31
Analyses	1,980 man-hr	17.00/man-hr	33,700	0.45
Total conversion costs			2,477,900	33.13
Total direct costs			2,951,800	39.47
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 7.0% of total depreciable investment			1,697,200	22.69
Average cost of capital and taxes at 8.6% of total capital investment			2,154,900	28.81
Overheads				
Plant, 50% of conversion costs less utilities			654,900	8.76
Administrative, 10% of operating labor			20,600	0.27
Total indirect costs			4,527,600	60.53
Total average annual revenue requirements			7,479,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	5.34	11.81	0.56	506.05

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[a] Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 20 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 633,500 tons/yr, 9,500 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 14,780 short tons/yr; solids disposal 77,790 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $12,857,000; total depreciable investment, $24,246,000; and total capital investment, $25,057,000.

TABLE A-3

LIMESTONE SLURRY PROCESS 200 MW EXISTING COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 25057000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11	5000	9500000	452400	10600	55600	0.0	8773700	0	8773700	8773700
12	5000	9500000	452400	10600	55600	0.0	8565200	0	8565200	17338900
13	5000	9500000	452400	10600	55600	0.0	8356700	0	8356700	25695600
14	5000	9500000	452400	10600	55600	0.0	8148200	0	8148200	33843800
15	5000	9500000	452400	10600	55600	0.0	7939600	0	7939600	41783400
16	3500	6650000	316700	7400	38900	0.0	7052200	0	7052200	48835600
17	3500	6650000	316700	7400	38900	0.0	6843700	0	6843700	55679300
18	3500	6650000	316700	7400	38900	0.0	6635200	0	6635200	62314500
19	3500	6650000	316700	7400	38900	0.0	6426700	0	6426700	68741200
20	3500	6650000	316700	7400	38900	0.0	6218200	0	6218200	74959400
21	1500	2850000	135700	3200	16700	0.0	5015800	0	5015800	79975200
22	1500	2850000	135700	3200	16700	0.0	4807300	0	4807300	84782500
23	1500	2850000	135700	3200	16700	0.0	4598800	0	4598800	89381300
24	1500	2850000	135700	3200	16700	0.0	4390300	0	4390300	93771600
25	1500	2850000	135700	3200	16700	0.0	4181800	0	4181800	97953400
26	1500	2850000	135700	3200	16700	0.0	3973300	0	3973300	101926700
27	1500	2850000	135700	3200	16700	0.0	3764800	0	3764800	105691500
28	1500	2850000	135700	3200	16700	0.0	3556200	0	3556200	109247700
29	1500	2850000	135700	3200	16700	0.0	3347700	0	3347700	112595400
30	1500	2850000	135700	3200	16700	0.0	3139200	0	3139200	115734600
TOT	57500	109250000	5202500	122000	639500		115734600	0	115734600	

	TOTAL OP. COST	TOTAL NET SALES REVENUE	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	22.25	0.0	22.25
MILLS PER KILOWATT-HOUR	10.06	0.0	10.06
CENTS PER MILLION BTU HEAT INPUT	105.94	0.0	105.94
DOLLARS PER TON OF SULFUR REMOVED	948.64	0.0	948.64
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	52811700	0	52811700
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	20.52	0.0	20.52
MILLS PER KILOWATT-HOUR	9.28	0.0	9.28
CENTS PER MILLION BTU HEAT INPUT	97.73	0.0	97.73
DOLLARS PER TON OF SULFUR REMOVED	875.82	0.0	875.82

TABLE A-4. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(200-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat irput allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	960,000	7.4
Feed preparation (feeders, curshers, ball mills, hoist, tanks, agitators, and pumps)	1,188,000	9.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	1,850,000	14.2
SO_2 absorption (two TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	4,034,000	30.8
Stack gas reheat (two indirect steam reheaters)	569,000	4.4
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,250,000	9.6
Subtotal	9,851,000	75.5
Services, utilities, and miscellaneous	591,000	4.6
Total process areas excluding pond construction	10,442,000	80.1
Pond construction	2,598,000	19.9
Total direct investment	13,040,000	100.0
Indirect Investment		
Engineering design and supervision	916,000	7.0
Architect and engineering contractor	207,000	1.6
Construction expense	2,039,000	15.6
Contractor fees	676,000	5.2
Total indirect investment	3,838,000	29.4
Contingency	3,376,000	25.9
Total fixed investment	20,254,000	155.3
Other Capital Charges		
Allowance for startup and modifications	1,766,000	13.5
Interest during construction	2,430,000	18.7
Total depreciable investment	24,450,000	187.5
Land	514,000	3.9
Working capital	497,000	3.8
Total capital investment	25,461,000	195.2

[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-5. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(200-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	65,600 tons	7.00/ton	459,200	6.42
Total raw materials cost			459,200	6.42
Conversion costs				
Operating labor and supervision	16,440 man-hr	12.50/man-hr	205,500	2.87
Utilities				
Steam	200,300 MBtu	2.00/MBtu	400,600	5.60
Process water	103,700 kgal	0.12/kgal	12,400	0.17
Electricity	23,173,000 kWh	0.031/kWh	718,400	10.04
Maintenance				
Labor and material			1,017,700	14.24
Analyses	1,980 man-hr	17.00/man-hr	33,700	0.47
Total conversion costs			2,388,300	33.39
Total direct costs			2,847,500	39.81
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			1,467,000	20.51
Average cost of capital and taxes at 8.6% of total capital investment			2,189,600	30.61
Overheads				
Plant, 50% of conversion costs less utilities			628,500	8.78
Administrative, 10% of operating labor			20,600	0.29
Total indirect costs			4,305,700	60.19
Total average annual revenue requirements			7,153,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	5.11	11.67	0.56	499.87

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 613,200 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 14,310 short tons/yr; solids disposal 75,310 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $13,040,000; total depreciable investment, $24,450,000; and total capital investment, $25,461,000.

TABLE A-6

LIMESTONE SLURRY PROCESS 200 MW NEW COAL-FIRED POWER UNIT 4.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 25461000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	613300	14300	75300	0.0	9343100	0	9343100	9343100
2	7000	12880000	613300	14300	75300	0.0	9202900	0	9202900	18546000
3	7000	12880000	613300	14300	75300	0.0	9062700	0	9062700	27608700
4	7000	12880000	613300	14300	75300	0.0	8922600	0	8922600	36531300
5	7000	12880000	613300	14300	75300	0.0	8782400	0	8782400	45313700
6	7000	12880000	613300	14300	75300	0.0	8642200	0	8642200	53955900
7	7000	12880000	613300	14300	75300	0.0	8502000	0	8502000	62457900
8	7000	12880000	613300	14300	75300	0.0	8361800	0	8361800	70819700
9	7000	12880000	613300	14300	75300	0.0	8221700	0	8221700	79041400
10	7000	12880000	613300	14300	75300	0.0	8081500	0	8081500	87122900
11	5000	9200000	438100	10200	53800	0.0	7111000	0	7111000	94233900
12	5000	9200000	438100	10200	53800	0.0	6970800	0	6970800	101204700
13	5000	9200000	438100	10200	53800	0.0	6830600	0	6830600	108035300
14	5000	9200000	438100	10200	53800	0.0	6690500	0	6690500	114725800
15	5000	9200000	438100	10200	53800	0.0	6550300	0	6550300	121276100
16	3500	6440000	306700	7200	37700	0.0	5755300	0	5755300	127031400
17	3500	6440000	306700	7200	37700	0.0	5615100	0	5615100	132646500
18	3500	6440000	306700	7200	37700	0.0	5474900	0	5474900	138121400
19	3500	6440000	306700	7200	37700	0.0	5334800	0	5334800	143456200
20	3500	6440000	306700	7200	37700	0.0	5194600	0	5194600	148650800
21	1500	2760000	131400	3100	16100	0.0	4096200	0	4096200	152747000
22	1500	2760000	131400	3100	16100	0.0	3956000	0	3956000	156703000
23	1500	2760000	131400	3100	16100	0.0	3815800	0	3815800	160518800
24	1500	2760000	131400	3100	16100	0.0	3675700	0	3675700	164194500
25	1500	2760000	131400	3100	16100	0.0	3535500	0	3535500	167730000
26	1500	2760000	131400	3100	16100	0.0	3395300	0	3395300	171125300
27	1500	2760000	131400	3100	16100	0.0	3255100	0	3255100	174380400
28	1500	2760000	131400	3100	16100	0.0	3114900	0	3114900	177495300
29	1500	2760000	131400	3100	16100	0.0	2974800	0	2974800	180470100
30	1500	2760000	131400	3100	16100	0.0	2834600	0	2834600	183304700
TOT	127500	234600000	11171000	261000	1371500		183304700	0	183304700	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							16.41	0.0	16.41	
MILLS PER KILOWATT-HOUR							7.19	0.0	7.19	
CENTS PER MILLION BTU HEAT INPUT							78.13	0.0	78.13	
DOLLARS PER TON OF SULFUR REMOVED							702.32	0.0	702.32	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							65253700	0	65253700	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							14.99	0.0	14.99	
MILLS PER KILOWATT-HOUR							6.56	0.0	6.56	
CENTS PER MILLION BTU HEAT INPUT							71.36	0.0	71.36	
DOLLARS PER TON OF SULFUR REMOVED							642.26	0.0	642.26	

TABLE A-7. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW existing coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	1,940,000	7.2
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,870,000	7.0
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	5,111,000	19.0
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,424,000	35.1
Stack gas reheat (four indirect steam reheaters)	1,312,000	4.9
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,826,000	6.8
Subtotal	21,483,000	80.0
Services, utilities, and miscellaneous	1,289,000	4.8
Total process areas excluding pond construction	22,772,000	84.8
Pond construction	4,084,000	15.2
Total direct investment	26,856,000	100.0
Indirect Investment		
Engineering design and supervision	1,174,000	4.4
Architect and engineering contractor	265,000	1.0
Construction expense	3,764,000	13.9
Contractor fees	1,170,000	4.4
Total indirect investment	6,373,000	23.7
Contingency	6,646,000	24.8
Total fixed investment	39,875,000	148.5
Other Capital Charges		
Allowance for startup and modifications	3,579,000	13.3
Interest during construction	4,785,000	17.8
Total depreciable investment	48,239,000	179.6
Land	820,000	3.1
Working capital	1,061,000	3.9
Total capital investment	50,120,000	186.6

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[a] Basis
Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-8. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW existing coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	163,900 tons	7.00/ton	1,147,300	7.76
Total raw materials cost			1,147,300	7.76
Conversion costs				
Operating labor and supervision	25,990 man-hr	12.50/man-hr	324,900	2.20
Utilities				
Steam	500,700 MBtu	2.00/MBtu	1,001,400	6.77
Process water	257,900 kgal	0.12/kgal	30,900	0.21
Electricity	57,930,000 kWh	0.029/kWh	1,680,000	11.36
Maintenance				
Labor and material			1,944,300	13.14
Analyses	3,760 man-hr	17.00/man-hr	63,900	0.43
Total conversion costs			5,045,400	34.11
Total direct costs			6,192,700	41.87
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			3,087,300	20.88
Average cost of capital and taxes at 8.6% of total capital investment			4,310,300	29.14
Overheads				
Plant, 50% of conversion costs less utilities			1,166,600	7.89
Administrative, 10% of operating labor			32,500	0.22
Total indirect costs			8,596,700	58.13
Total average annual revenue requirements			14,789,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	4.23	9.65	0.46	413.34

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 25 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,533,350 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 35,780 short tons/yr; solids disposal 188,300 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $26,856,000; total depreciable investment, $48,239,000; and total capital investment, $50,120,000.

TABLE A-9

LIMESTONE SLURRY PROCESS 500 MW EXISTING COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 50120000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1533300	35800	188300	0.0	19099600	0	19099600	19099600
7	7000	32200000	1533300	35800	188300	0.0	18767700	0	18767700	37867300
8	7000	32200000	1533300	35800	188300	0.0	18435900	0	18435900	56303200
9	7000	32200000	1533300	35800	188300	0.0	18104000	0	18104000	74407200
10	7000	32200000	1533300	35800	188300	0.0	17772100	0	17772100	92179300
11	5000	23000000	1095200	25600	134500	0.0	15631300	0	15631300	107810600
12	5000	23000000	1095200	25600	134500	0.0	15299400	0	15299400	123110000
13	5000	23000000	1095200	25600	134500	0.0	14967500	0	14967500	138077500
14	5000	23000000	1095200	25600	134500	0.0	14635600	0	14635600	152713100
15	5000	23000000	1095200	25600	134500	0.0	14303700	0	14303700	167016800
16	3500	16100000	766700	17900	94200	0.0	12557000	0	12557000	179573800
17	3500	16100000	766700	17900	94200	0.0	12225100	0	12225100	191798900
18	3500	16100000	766700	17900	94200	0.0	11893200	0	11893200	203692100
19	3500	16100000	766700	17900	94200	0.0	11561400	0	11561400	215253500
20	3500	16100000	766700	17900	94200	0.0	11229500	0	11229500	226483000
21	1500	6900000	328600	7700	40400	0.0	8858100	0	8858100	235341100
22	1500	6900000	328600	7700	40400	0.0	8526200	0	8526200	243867300
23	1500	6900000	328600	7700	40400	0.0	8194300	0	8194300	252061600
24	1500	6900000	328600	7700	40400	0.0	7862400	0	7862400	259924000
25	1500	6900000	328600	7700	40400	0.0	7530500	0	7530500	267454500
26	1500	6900000	328600	7700	40400	0.0	7198600	0	7198600	274653100
27	1500	6900000	328600	7700	40400	0.0	6866700	0	6866700	281519800
28	1500	6900000	328600	7700	40400	0.0	6534800	0	6534800	288054600
29	1500	6900000	328600	7700	40400	0.0	6202900	0	6202900	294257500
30	1500	6900000	328600	7700	40400	0.0	5871100	0	5871100	300128600
TOT	92500	425500000	20262000	473500	2484000		300128600	0	300128600	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	14.81	0.0	14.81
MILLS PER KILOWATT-HOUR	6.49	0.0	6.49
CENTS PER MILLION BTU HEAT INPUT	70.54	0.0	70.54
DOLLARS PER TON OF SULFUR REMOVED	633.85	0.0	633.85
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	122034600	0	122034600
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	13.29	0.0	13.29
MILLS PER KILOWATT-HOUR	5.82	0.0	5.82
CENTS PER MILLION BTU HEAT INPUT	63.29	0.0	63.29
DOLLARS PER TON OF SULFUR REMOVED	569.19	0.0	569.19

TABLE A-10. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit,
2.0% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	974,000	4.7
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,179,000	5.6
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,120,000	19.7
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	8,282,000	39.6
Stack gas reheat (four indirect steam reheaters)	1,222,000	5.9
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,290,000	6.2
Subtotal	17,067,000	81.7
Services, utilites, and miscellaneous	1,024,000	4.9
Total process areas excluding pond construction	18,091,000	86.6
Pond construction	2,800,000	13.4
Total direct investment	20,891,000	100.0
Indirect Investment		
Engineering design and supervision	1,130,000	5.4
Architect and engineering contractor	260,000	1.2
Construction expense	3,071,000	14.8
Contractor fees	967,000	4.6
Total indirect investment	5,428,000	26.0
Contingency	5,264,000	25.2
Total fixed investment	31,583,000	151.2
Other Capital Charges		
Allowance for startup and modifications	2,878,000	13.8
Interest during construction	3,790,000	18.1
Total depreciable investment	38,251,000	183.1
Land	563,000	2.7
Working capital	827,000	3.9
Total capital investment	39,641,000	189.7

a. Basis
- Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 175°F by indirect steam reheat.
- Minimum in-process storage; only pumps are spared.
- Disposal pond located 1 mi from power plant.
- Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-11. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit,
2.0% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	73,600 tons	7.00/ton	515,200	4.44
Total raw materials cost			515,200	4.44
Conversion costs				
Operating labor and supervision	23,280 man-hr	12.50/man-hr	291,000	2.50
Utilities				
Steam	489,800 MBtu	2.00/MBtu	979,600	8.43
Process water	215,000 kgal	0.12/kgal	25,800	0.22
Electricity	53,505,000 kWh	0.029/kWh	1,551,600	13.35
Maintenance				
Labor and material			1,531,300	13.17
Analyses	3,370 man-hr	17.00/man-hr	57,300	0.49
Total conversion costs			4,436,600	38.16
Total direct costs			4,951,800	42.60
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,295,100	19.74
Average cost of capital and taxes at 8.6% of total capital investment			3,409,100	29.33
Overheads				
Plant, 50% of conversion costs less utilities			939,800	8.08
Administrative, 10% of operating labor			29,100	0.25
Total indirect costs			6,673,100	57.40
Total average annual revenue requirements			11,624,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	3.32	7.75	0.37	717.59

a. Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- S removed, 16,200 short tons/yr; solids disposal 85,260 tons/yr Ca solids including only hydrate water.
- Investment and revenue requirement for removal and disposal of flyash excluded.
- Total direct investment, $20,891,000; total depreciable investment, $38,251,000; and total capital investment, $39,641,000.

TABLE A-12

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LIMESTONE SLURRY PROCESS 500 MW NEW COAL-FIRED POWER UNIT 2.0% S IN COAL REGULATED CO. ECONOMICS

                                         FIXED INVESTMENT:  $   39641000
                                                                                      TOTAL
                                                                                    OP. COST
                                              SULFUR      BY-PRODUCT                INCLUDING
YEARS ANNUAL   POWER UNIT     POWER UNIT     REMOVED        RATE,                   REGULATED             NET ANNUAL   CUMULATIVE
AFTER OPERA-     HEAT            FUEL           BY        EQUIVALENT   NET REVENUE,  ROI FOR      TOTAL     INCREASE   NET INCREASE
POWER TION,   REQUIREMENT,  CONSUMPTION,   POLLUTION     TONS/YEAR      $/TON        POWER        NET     (DECREASE)   (DECREASE)
UNIT  KW-HR/  MILLION BTU     TONS COAL     CONTROL                                 COMPANY,     SALES    IN COST OF   IN COST OF
START   KW       /YEAR          /YEAR       PROCESS,       DRY           DRY        $/YEAR     REVENUE,    POWER,       POWER,
                                           TONS/YEAR      SOLIDS        SOLIDS                  $/YEAR       $            $
------------------------------------------------------------------------------------------------------------------------------
  1    7000    31500000       1500000       16200         85300          0.0       15034400         0    15034400     15034400
  2    7000    31500000       1500000       16200         85300          0.0       14815100         0    14815100     29849500
  3    7000    31500000       1500000       16200         85300          0.0       14595800         0    14595800     44445300
  4    7000    31500000       1500000       16200         85300          0.0       14376500         0    14376500     58821800
  5    7000    31500000       1500000       16200         85300          0.0       14157200         0    14157200     72979000
  6    7000    31500000       1500000       16200         85300          0.0       13937900         0    13937900     86916900
  7    7000    31500000       1500000       16200         85300          0.0       13718600         0    13718600    100635500
  8    7000    31500000       1500000       16200         85300          0.0       13499300         0    13499300    114134800
  9    7000    31500000       1500000       16200         85300          0.0       13280000         0    13280000    127414800
 10    7000    31500000       1500000       16200         85300          0.0       13060700         0    13060700    140475500
 11    5000    22500000       1071400       11600         60900          0.0       11390500         0    11390500    151866000
 12    5000    22500000       1071400       11600         60900          0.0       11171200         0    11171200    163037200
 13    5000    22500000       1071400       11600         60900          0.0       10951900         0    10951900    173989100
 14    5000    22500000       1071400       11600         60900          0.0       10732600         0    10732600    184721700
 15    5000    22500000       1071400       11600         60900          0.0       10513300         0    10513300    195235000
 16    3500    15750000        750000        8100         42600          0.0        9160000         0     9160000    204395000
 17    3500    15750000        750000        8100         42600          0.0        8940700         0     8940700    213335700
 18    3500    15750000        750000        8100         42600          0.0        8721400         0     8721400    222057100
 19    3500    15750000        750000        8100         42600          0.0        8502100         0     8502100    230559200
 20    3500    15750000        750000        8100         42600          0.0        8282800         0     8282800    238842000
 21    1500     6750000        321400        3500         18300          0.0        6429800         0     6429800    245271800
 22    1500     6750000        321400        3500         18300          0.0        6210500         0     6210500    251482300
 23    1500     6750000        321400        3500         18300          0.0        5991200         0     5991200    257473500
 24    1500     6750000        321400        3500         18300          0.0        5771900         0     5771900    263245400
 25    1500     6750000        321400        3500         18300          0.0        5552600         0     5552600    268798000
 26    1500     6750000        321400        3500         18300          0.0        5333300         0     5333300    274131300
 27    1500     6750000        321400        3500         18300          0.0        5114000         0     5114000    279245300
 28    1500     6750000        321400        3500         18300          0.0        4894700         0     4894700    284140000
 29    1500     6750000        321400        3500         18300          0.0        4675400         0     4675400    288815400
 30    1500     6750000        321400        3500         18300          0.0        4456100         0     4456100    293271500

TOT  127500   573750000      27321000      295500       1553500                   293271500         0   293271500
   LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST
                        DOLLARS PER TON OF COAL BURNED                                 10.73      0.0       10.73
                        MILLS PER KILOWATT-HOUR                                         4.60      0.0        4.60
                        CENTS PER MILLION BTU HEAT INPUT                               51.11      0.0       51.11
                        DOLLARS PER TON OF SULFUR REMOVED                             992.46      0.0      992.46
PROCESS COST DISCOUNTED AT  11.6% TO INITIAL YEAR, DOLLARS                         104931000         0   104931000
   LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT
                        DOLLARS PER TON OF COAL BURNED                                  9.85      0.0        9.85
                        MILLS PER KILOWATT-HOUR                                         4.22      0.0        4.22
                        CENTS PER MILLION BTU HEAT INPUT                               46.92      0.0       46.92
                        DOLLARS PER TON OF SULFUR REMOVED                             911.65      0.0      911.65
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TABLE A-13. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	1,759,000	6.8
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,740,000	6.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,318,000	16.6
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	8,918,000	34.3
Stack gas reheat (four indirect steam reheaters)	1,282,000	4.9
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,658,000	6.4
Subtotal	19,675,000	75.7
Services, utilities, and miscellaneous	1,180,000	4.5
Total process areas excluding pond construction	20,855,000	80.2
Pond construction	5,145,000	19.8
Total direct investment	26,000,000	100.0
Indirect Investment		
Engineering design and supervision	1,207,000	4.6
Architect and engineering contractor	268,000	1.0
Construction expense	3,617,000	13.9
Contractor fees	1,142,000	4.4
Total indirect investment	6,234,000	23.9
Contingency	6,447,000	24.8
Total fixed investment	38,681,000	148.7
Other Capital Charges		
Allowance for startup and modifications	3,354,000	12.9
Interest during construction	4,642,000	17.9
Total depreciable investment	46,677,000	179.5
Land	1,030,000	4.0
Working capital	1,021,000	3.9
Total capital investment	48,728,000	187.4

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-14. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	158,300 tons	7.00/ton	1,108,100	7.86
Total raw materials cost			1,108,100	7.86
Conversion costs				
Operating labor and supervision	25,990 man-hr	12.50/man-hr	324,900	2.30
Utilities				
Steam	489,800 MBtu	2.00/MBtu	979,600	6.95
Process water	247,400 kgal	0.12/kgal	29,700	0.21
Electricity	56,670,000 kWh	0.029/kWh	1,643,400	11.65
Maintenance				
Labor and material			1,822,800	12.93
Analyses	3,760 man-hr	17.00/man-hr	63,900	0.45
Total conversion costs			4,864,300	34.49
Total direct costs			5,972,400	42.35
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,800,600	19.86
Average cost of capital and taxes at 8.6% of total capital investment			4,190,600	29.72
Overheads				
Plant, 50% of conversion costs less utilities			1,105,800	7.84
Administrative, 10% of operating labor			32,500	0.23
Total indirect costs			8,129,500	57.65
Total average annual revenue requirements			14,101,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	4.03	9.40	0.45	402.91

a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 35,000 short tons/yr; solids disposal 184,200 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $26,000,000; total depreciable investment, $46,677,000; and total capital investment, $48,728,000.

TABLE A-15

LIMESTONE SLURRY PROCESS 500 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 48728000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/ KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	35000	184200	0.0	18292200	0	18292200	18292200
2	7000	31500000	1500000	35000	184200	0.0	18024600	0	18024600	36316800
3	7000	31500000	1500000	35000	184200	0.0	17757000	0	17757000	54073800
4	7000	31500000	1500000	35000	184200	0.0	17489400	0	17489400	71563200
5	7000	31500000	1500000	35000	184200	0.0	17221800	0	17221800	88785000
6	7000	31500000	1500000	35000	184200	0.0	16954100	0	16954100	105739100
7	7000	31500000	1500000	35000	184200	0.0	16686500	0	16686500	122425600
8	7000	31500000	1500000	35000	184200	0.0	16418900	0	16418900	138844500
9	7000	31500000	1500000	35000	184200	0.0	16151300	0	16151300	154995800
10	7000	31500000	1500000	35000	184200	0.0	15883700	0	15883700	170879500
11	5000	22500000	1071400	25000	131600	0.0	13871300	0	13871300	184750800
12	5000	22500000	1071400	25000	131600	0.0	13603700	0	13603700	198354500
13	5000	22500000	1071400	25000	131600	0.0	13336000	0	13336000	211690500
14	5000	22500000	1071400	25000	131600	0.0	13068400	0	13068400	224758900
15	5000	22500000	1071400	25000	131600	0.0	12800800	0	12800800	237559700
16	3500	15750000	750000	17500	92100	0.0	11169400	0	11169400	248729100
17	3500	15750000	750000	17500	92100	0.0	10901800	0	10901800	259630900
18	3500	15750000	750000	17500	92100	0.0	10634200	0	10634200	270265100
19	3500	15750000	750000	17500	92100	0.0	10366500	0	10366500	280631600
20	3500	15750000	750000	17500	92100	0.0	10098900	0	10098900	290730500
21	1500	6750000	321400	7500	39500	0.0	7868600	0	7868600	298599100
22	1500	6750000	321400	7500	39500	0.0	7601000	0	7601000	306200100
23	1500	6750000	321400	7500	39500	0.0	7333400	0	7333400	313533500
24	1500	6750000	321400	7500	39500	0.0	7065800	0	7065800	320599300
25	1500	6750000	321400	7500	39500	0.0	6798200	0	6798200	327397500
26	1500	6750000	321400	7500	39500	0.0	6530500	0	6530500	333928000
27	1500	6750000	321400	7500	39500	0.0	6262900	0	6262900	340190900
28	1500	6750000	321400	7500	39500	0.0	5995300	0	5995300	346186200
29	1500	6750000	321400	7500	39500	0.0	5727700	0	5727700	351913900
30	1500	6750000	321400	7500	39500	0.0	5460100	0	5460100	357374000
TOT	127500	573750000	27321000	637500	3355500					
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST							357374000	0	357374000	
DOLLARS PER TON OF COAL BURNED							13.08	0.0	13.08	
MILLS PER KILOWATT-HOUR							5.61	0.0	5.61	
CENTS PER MILLION BTU HEAT INPUT							62.29	0.0	62.29	
DOLLARS PER TON OF SULFUR REMOVED							560.59	0.0	560.59	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							127709200	0	127709200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							11.99	0.0	11.99	
MILLS PER KILOWATT-HOUR							5.14	0.0	5.14	
CENTS PER MILLION BTU HEAT INPUT							57.10	0.0	57.10	
DOLLARS PER TON OF SULFUR REMOVED							513.92	0.0	513.92	

TABLE A-16. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit,
5.0% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	1,931,000	6.6
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	2,028,000	6.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,327,000	14.8
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	8,948,000	30.6
Stack gas reheat (four indirect steam reheaters)	1,283,000	4.4
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,957,000	6.7
Subtotal	20,474,000	70.0
Services, utilities, and miscellaneous	1,228,000	4.2
Total process areas excluding pond construction	21,702,000	74.2
Pond construction	7,553,000	25.8
Total direct investment	29,255,000	100.0
Indirect Investment		
Engineering design and supervision	1,274,000	4.4
Architect and engineering contractor	275,000	0.9
Construction expense	3,911,000	13.3
Contractor fees	1,249,000	4.3
Total indirect investment	6,709,000	22.9
Contingency	7,193,000	24.6
Total fixed investment	43,157,000	147.5
Other Capital Charges		
Allowance for startup and modifications	3,560,000	12.2
Interest during construction	5,179,000	17.7
Total depreciable investment	51,896,000	177.4
Land	1,511,000	5.2
Working capital	1,214,000	4.1
Total capital investment	54,621,000	186.7

a. Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-17. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit,
5.0% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	266,500 tons	7.00/ton	1,865,500	11.64
Total raw materials cost			1,865,500	11.64
Conversion costs				
Operating labor and supervision	27,910 man-hr	12.50/man-hr	348,900	2.18
Utilities				
Steam	489,800 MBtu	2.00/MBtu	979,600	6.11
Process water	295,300 kgal	0.12/kgal	35,400	0.22
Electricity	59,828,000 kWh	0.029/kWh	1,735,000	10.82
Maintenance				
Labor and material			1,962,800	12.24
Analyses	4,040 man-hr	17.00/man-hr	68,700	0.43
Total conversion costs			5,130,400	32.00
Total direct costs			6,995,900	43.64
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,113,800	19.42
Average cost of capital and taxes at 8.6% of total capital investment			4,697,400	29.30
Overheads				
Plant, 50% of conversion costs less utilities			1,190,200	7.42
Administrative, 10% of operating labor			34,900	0.22
Total indirect costs			9,036,300	56.36
Total average annual revenue requirements			16,032,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	4.58	10.69	0.51	295.91

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[a] Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 54,180 short tons/yr; solids disposal 285,140 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $29,255,000; total depreciable investment, $51,896,000; and total capital investment, $54,621,000.

TABLE A-18

LIMESTONE SLURRY PROCESS 500 MW NEW COAL-FIRED POWER UNIT 5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 54621000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	54200	285100	0.0	20730200	0	20730200	20730200
2	7000	31500000	1500000	54200	285100	0.0	20432700	0	20432700	41162900
3	7000	31500000	1500000	54200	285100	0.0	20135100	0	20135100	61298000
4	7000	31500000	1500000	54200	285100	0.0	19837600	0	19837600	81135600
5	7000	31500000	1500000	54200	285100	0.0	19540000	0	19540000	100675600
6	7000	31500000	1500000	54200	285100	0.0	19242500	0	19242500	119918100
7	7000	31500000	1500000	54200	285100	0.0	18945000	0	18945000	138863100
8	7000	31500000	1500000	54200	285100	0.0	18647400	0	18647400	157510500
9	7000	31500000	1500000	54200	285100	0.0	18349900	0	18349900	175860400
10	7000	31500000	1500000	54200	285100	0.0	18052300	0	18052300	193912700
11	5000	22500000	1071400	38700	203700	0.0	15715600	0	15715600	209628300
12	5000	22500000	1071400	38700	203700	0.0	15418000	0	15418000	225046300
13	5000	22500000	1071400	38700	203700	0.0	15120500	0	15120500	240166800
14	5000	22500000	1071400	38700	203700	0.0	14823000	0	14823000	254989800
15	5000	22500000	1071400	38700	203700	0.0	14525400	0	14525400	269515200
16	3500	15750000	750000	27100	142600	0.0	12639000	0	12639000	282154200
17	3500	15750000	750000	27100	142600	0.0	12341400	0	12341400	294495600
18	3500	15750000	750000	27100	142600	0.0	12043900	0	12043900	306539500
19	3500	15750000	750000	27100	142600	0.0	11746300	0	11746300	318285800
20	3500	15750000	750000	27100	142600	0.0	11448800	0	11448800	329734600
21	1500	6750000	321400	11600	61100	0.0	8876800	0	8876800	338611400
22	1500	6750000	321400	11600	61100	0.0	8579200	0	8579200	347190600
23	1500	6750000	321400	11600	61100	0.0	8281700	0	8281700	355472300
24	1500	6750000	321400	11600	61100	0.0	7984100	0	7984100	363456400
25	1500	6750000	321400	11600	61100	0.0	7686600	0	7686600	371143000
26	1500	6750000	321400	11600	61100	0.0	7389000	0	7389000	378532000
27	1500	6750000	321400	11600	61100	0.0	7091500	0	7091500	385623500
28	1500	6750000	321400	11600	61100	0.0	6794000	0	6794000	392417500
29	1500	6750000	321400	11600	61100	0.0	6496400	0	6496400	398913900
30	1500	6750000	321400	11600	61100	0.0	6198900	0	6198900	405112800
TOT	127500	573750000	27321000	987000	5193500		405112800	0	405112800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	14.83	0.0	14.83
MILLS PER KILOWATT-HOUR	6.35	0.0	6.35
CENTS PER MILLION BTU HEAT INPUT	70.61	0.0	70.61
DOLLARS PER TON OF SULFUR REMOVED	410.45	0.0	410.45
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	144837500	0	144837500
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	13.60	0.0	13.60
MILLS PER KILOWATT-HOUR	5.83	0.0	5.83
CENTS PER MILLION BTU HEAT INPUT	64.76	0.0	64.76
DOLLARS PER TON OF SULFUR REMOVED	376.40	0.0	376.40

TABLE A-19. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(1000-MW existing coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	2,434,000	5.9
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	2,412,000	5.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	8,690,000	21.2
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	14,301,000	35.0
Stack gas reheat (four indirect steam reheaters)	2,026,000	4.9
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	2,316,000	5.7
Subtotal	32,179,000	78.6
Services, utilities, and miscellaneous	1,931,000	4.7
Total process areas excluding pond construction	34,110,000	83.3
Pond construction	6,856,000	16.7
Total direct investment	40,966,000	100.0
Indirect Investment		
Engineering design and supervision	1,255,000	3.1
Architect and engineering contractor	273,000	0.7
Construction expense	5,323,000	13.0
Contractor fees	1,613,000	3.9
Total indirect investment	8,464,000	20.7
Contingency	9,886,000	24.1
Total fixed investment	59,316,000	144.8
Other Capital Charges		
Allowance for startup and modifications	5,246,000	12.8
Interest during construction	7,118,000	17.4
Total depreciable investment	71,680,000	175.0
Land	1,376,000	3.4
Working capital	1,774,000	4.3
Total capital investment	74,830,000	182.7

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[a] Basis
Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-20. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(1000-MW existing coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	320,600 tons	7.00/ton	2,244,200	9.65
Total raw materials cost			2,244,200	9.65
Conversion costs				
Operating labor and supervision	36,750 man-hr	12.50/man-hr	459,400	1.98
Utilities				
Steam	979,700 MBtu	2.00/MBtu	1,959,400	8.43
Process water	503,400 kgal	0.12/kgal	60,400	0.26
Electricity	113,344,000 kWh	0.028/kWh	3,173,600	13.65
Maintenance				
Labor and material			2,593,400	11.16
Analyses	6,100 man-hr	17.00/man-hr	103,700	0.45
Total conversion costs			8,349,900	35.93
Total direct costs			10,594,100	45.58
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			4,587,500	19.74
Average cost of capital and taxes at 8.6% of total capital investment			6,435,400	27.69
Overheads				
Plant, 50% of conversion costs less utilities			1,578,300	6.79
Administrative, 10% of operating labor			45,900	0.20
Total indirect costs			12,647,100	54.42
Total average annual revenue requirements			23,241,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	3.32	7.75	0.37	332.02

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 25 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 2,999,850 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 70,000 short tons/yr; solids disposal 368,400 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $40,966,000; total depreciable investment, $71,680,000; and total capital investment, $74,830,000.

TABLE A-21

LIMESTONE SLURRY PROCESS 1000 MW EXISTING COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 74830000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	63000000	3000000	70000	368400	0.0	29676700	0	29676700	29676700
7	7000	63000000	3000000	70000	368400	0.0	29183500	0	29183500	58860200
8	7000	63000000	3000000	70000	368400	0.0	28690300	0	28690300	87550500
9	7000	63000000	3000000	70000	368400	0.0	28197200	0	28197200	115747700
10	7000	63000000	3000000	70000	368400	0.0	27704000	0	27704000	143451700
11	5000	45000000	2142900	50000	263100	0.0	24114800	0	24114800	167566500
12	5000	45000000	2142900	50000	263100	0.0	23621600	0	23621600	191188100
13	5000	45000000	2142900	50000	263100	0.0	23128500	0	23128500	214316600
14	5000	45000000	2142900	50000	263100	0.0	22635300	0	22635300	236951900
15	5000	45000000	2142900	50000	263100	0.0	22142100	0	22142100	259094000
16	3500	31500000	1500000	35000	184200	0.0	19251200	0	19251200	278345200
17	3500	31500000	1500000	35000	184200	0.0	18758000	0	18758000	297103200
18	3500	31500000	1500000	35000	184200	0.0	18264900	0	18264900	315368100
19	3500	31500000	1500000	35000	184200	0.0	17771700	0	17771700	333139800
20	3500	31500000	1500000	35000	184200	0.0	17278500	0	17278500	350418300
21	1500	13500000	642900	15000	78900	0.0	13389200	0	13389200	363807500
22	1500	13500000	642900	15000	78900	0.0	12896000	0	12896000	376703500
23	1500	13500000	642900	15000	78900	0.0	12402900	0	12402900	389106400
24	1500	13500000	642900	15000	78900	0.0	11909700	0	11909700	401016100
25	1500	13500000	642900	15000	78900	0.0	11416600	0	11416600	412432700
26	1500	13500000	642900	15000	78900	0.0	10923400	0	10923400	423356100
27	1500	13500000	642900	15000	78900	0.0	10430200	0	10430200	433786300
28	1500	13500000	642900	15000	78900	0.0	9937100	0	9937100	443723400
29	1500	13500000	642900	15000	78900	0.0	9443900	0	9443900	453167300
30	1500	13500000	642900	15000	78900	0.0	8950800	0	8950800	462118100
TOT	92500	832500000	39643500	925000	4867500					

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 LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST                     462118100        0   462118100
                DOLLARS PER TON OF COAL BURNED
                MILLS PER KILOWATT-HOUR                                              11.66      0.0       11.66
                CENTS PER MILLION BTU HEAT INPUT                                      5.00      0.0        5.00
                DOLLARS PER TON OF SULFUR REMOVED                                    55.51      0.0       55.51
PROCESS COST DISCOUNTED AT  11.6% TO INITIAL YEAR, DOLLARS                          499.59      0.0      499.59
 LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED   188891100        0   188891100
                                                                      PROCESS COST OVER LIFE OF POWER UNIT
                DOLLARS PER TON OF COAL BURNED
                MILLS PER KILOWATT-HOUR                                              10.52      0.0       10.52
                CENTS PER MILLION BTU HEAT INPUT                                      4.51      0.0        4.51
                DOLLARS PER TON OF SULFUR REMOVED                                    50.07      0.0       50.07
                                                                                    450.71      0.0      450.71
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TABLE A-22. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(1000-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	2,199,000	5.7
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	2,229,000	5.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	7,135,000	18.3
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	13,087,000	33.7
Stack gas reheat (four indirect steam reheaters)	1,875,000	4.8
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	2,104,000	5.4
Subtotal	28,629,000	73.6
Services, utilities, and miscellaneous	1,718,000	4.4
Total process areas excluding pond construction	30,347,000	78.0
Pond construction	8,547,000	22.0
Total direct investment	38,894,000	100.0
Indirect Investment		
Engineering design and supervision	1,299,000	3.3
Architect and engineering contractor	277,000	0.7
Construction expense	5,019,000	12.9
Contractor fees	1,551,000	4.0
Total indirect investment	8,146,000	20.9
Contingency	9,408,000	24.2
Total fixed investment	56,448,000	145.1
Other Capital Charges		
Allowance for startup and modifications	4,790,000	12.3
Interest during construction	6,774,000	17.5
Total depreciable investment	68,012,000	174.9
Land	1,717,000	4.4
Working capital	1,694,000	4.3
Total capital investment	71,423,000	183.6

[a] Basis
Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-23. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(1000-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	309,900 tons	7.00/ton	2,169,300	9.92
Total raw materials cost			2,169,300	9.92
Conversion costs				
Operating labor and supervision	36,750 man-hr	12.50/man-hr	459,400	2.10
Utilities				
Steam	947,000 MBtu	2.00/MBtu	1,894,000	8.66
Process water	487,200 kgal	0.12/kgal	58,500	0.27
Electricity	109,566,000 kWh	0.028/kWh	3,067,800	14.03
Maintenance				
Labor and material			2,380,700	10.88
Analyses	6,100 man-hr	17.00/man-hr	103,700	0.47
Total conversion costs			7,964,100	36.41
Total direct costs			10,133,400	46.33
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,080,700	18.65
Average cost of capital and taxes at 8.6% of total capital investment			6,142,400	28.08
Overheads				
Plant, 50% of conversion costs less utilities			1,471,900	6.73
Administrative, 10% of operating labor			45,900	0.21
Total indirect costs			11,740,900	53.67
Total average annual revenue requirements			21,874,300	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	3.12	7.54	0.36	323.25

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[a] Basis

Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 2,900,100 tons/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 67,670 short tons/yr; solids disposal 356,140 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $38,894,000; total depreciable investment, $68,012,000; and total capital investment, $71,423,000.

TABLE A-24

LIMESTONE SLURRY PROCESS 1000 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 71423000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2900000	67700	356100	0.0	28016100	0	28016100	28016100
2	7000	60900000	2900000	67700	356100	0.0	27626100	0	27626100	55642200
3	7000	60900000	2900000	67700	356100	0.0	27236200	0	27236200	82878400
4	7000	60900000	2900000	67700	356100	0.0	26846200	0	26846200	109724600
5	7000	60900000	2900000	67700	356100	0.0	26456300	0	26456300	136180900
6	7000	60900000	2900000	67700	356100	0.0	26066400	0	26066400	162247300
7	7000	60900000	2900000	67700	356100	0.0	25676400	0	25676400	187923700
8	7000	60900000	2900000	67700	356100	0.0	25286500	0	25286500	213210200
9	7000	60900000	2900000	67700	356100	0.0	24896500	0	24896500	238106700
10	7000	60900000	2900000	67700	356100	0.0	24506600	0	24506600	262613300
11	5000	43500000	2071400	48400	254400	0.0	21155300	0	21155300	283768600
12	5000	43500000	2071400	48400	254400	0.0	20765400	0	20765400	304534000
13	5000	43500000	2071400	48400	254400	0.0	20375500	0	20375500	324909500
14	5000	43500000	2071400	48400	254400	0.0	19985500	0	19985500	344895000
15	5000	43500000	2071400	48400	254400	0.0	19595600	0	19595600	364490600
16	3500	30450000	1450000	33900	178100	0.0	16914400	0	16914400	381405000
17	3500	30450000	1450000	33900	178100	0.0	16524500	0	16524500	397929500
18	3500	30450000	1450000	33900	178100	0.0	16134600	0	16134600	414064100
19	3500	30450000	1450000	33900	178100	0.0	15744600	0	15744600	429808700
20	3500	30450000	1450000	33900	178100	0.0	15354700	0	15354700	445163400
21	1500	13050000	621400	14500	76300	0.0	11724600	0	11724600	456888000
22	1500	13050000	621400	14500	76300	0.0	11334700	0	11334700	468222700
23	1500	13050000	621400	14500	76300	0.0	10944700	0	10944700	479167400
24	1500	13050000	621400	14500	76300	0.0	10554800	0	10554800	489722200
25	1500	13050000	621400	14500	76300	0.0	10164900	0	10164900	499887100
26	1500	13050000	621400	14500	76300	0.0	9774900	0	9774900	509662000
27	1500	13050000	621400	14500	76300	0.0	9385000	0	9385000	519047000
28	1500	13050000	621400	14500	76300	0.0	8995000	0	8995000	528042000
29	1500	13050000	621400	14500	76300	0.0	8605100	0	8605100	536647100
30	1500	13050000	621400	14500	76300	0.0	8215200	0	8215200	544862300
TOT	127500	1109250000	52821000	1233500	6486500		544862300	0	544862300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							10.32	0.0	10.32	
MILLS PER KILOWATT-HOUR							4.27	0.0	4.27	
CENTS PER MILLION BTU HEAT INPUT							49.12	0.0	49.12	
DOLLARS PER TON OF SULFUR REMOVED							441.72	0.0	441.72	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							195672000	0	195672000	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							9.50	0.0	9.50	
MILLS PER KILOWATT-HOUR							3.94	0.0	3.94	
CENTS PER MILLION BTU HEAT INPUT							45.26	0.0	45.26	
DOLLARS PER TON OF SULFUR REMOVED							407.06	0.0	407.06	

TABLE A-25. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; trucking alternative)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	1,759,000	8.1
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,740,000	8.0
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,318,000	20.0
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	8,918,000	41.2
Stack gas reheat (four indirect steam reheaters)	1,282,000	5.9
Solids disposal (thickener, drum filters, tanks, agitators, pumps, and conveyors)	2,400,000	11.1
Subtotal	20,417,000	94.3
Services, utilities, and miscellaneous	1,225,000	5.7
Total direct investment	21,642,000	100.0
Indirect Investment		
Engineering design and supervision	1,255,000	5.8
Architect and engineering contractor	314,000	1.5
Construction expense	3,208,000	14.8
Contractor fees	993,000	4.6
Total indirect investment	5,770,000	26.7
Contingency	5,482,000	25.3
Total fixed investment	32,894,000	152.0
Other Capital Charges		
Allowance for startup and modifications	3,289,000	15.2
Interest during construction	3,947,000	18.2
Total depreciable investment	40,130,000	185.4
Land	361,000	1.7
Working capital	1,282,000	5.9
Trucking charge (including indirect charges)	534,000	2.5
Total capital investment	42,307,000	195.5

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[a] **Basis**

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal area located 1 mi from power plant.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-26. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission; trucking alternative)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	158,300 tons	7.00/ton	1,108,100	7.30
Total raw materials cost			1,108,100	7.30
Conversion costs				
Operating labor and supervision	43,500 man-hr	12.50/man-hr	543,800	3.58
Operating labor disposal equipment	42,000 man-hr	17.00/man-hr	714,000	4.71
Utilities				
Steam	489,800 MBtu	2.00/MBtu	979,600	6.46
Process water	247,400 kgal	0.12/kgal	29,700	0.20
Electricity	58,119,000 kWh	0.029/kWh	1,685,500	11.11
Fuel	245,930 gal	0.60/gal	147,600	0.97
Maintenance				
Labor and material			2,100,400	13.83
Analyses	3,980 man-hr	17.00/man-hr	67,700	0.45
Disposal land preparation	5.3 acres	1600/acre	8,500	0.06
Total conversion costs			6,276,800	41.37
Total direct costs			7,384,900	48.67
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,487,200	16.39
Average cost of capital and taxes at 8.6% of total capital investment			3,633,400	23.95
Overheads				
Plant, 50% of conversion costs less utilities			1,171,500	7.72
Administrative, 10% of operating labor			54,400	0.36
Trucking labor			441,000	2.91
Total indirect costs			7,787,500	51.33
Total average annual revenue requirements			15,172,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	4.33	10.11	0.48	433.50

a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 35,000 short tons/yr; solids disposal 184,200 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $21,642,000; total depreciable investment, $40,130,000; and total capital investment, $42,307,000.

TABLE A-27

LIMESTONE SLURRY PROCESS 500 MW NEW COAL-FIRED POWER UNIT 3.5%S IN COAL, TRUCKING, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 42307000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	34600	184200	0.0	18816000	0	18816000	18816000
2	7000	31500000	1500000	34600	184200	0.0	18585900	0	18585900	37401900
3	7000	31500000	1500000	34600	184200	0.0	18355800	0	18355800	55757700
4	7000	31500000	1500000	34600	184200	0.0	18125800	0	18125800	73883500
5	7000	31500000	1500000	34600	184200	0.0	17895700	0	17895700	91779200
6	7000	31500000	1500000	34600	184200	0.0	17665600	0	17665600	109444800
7	7000	31500000	1500000	34600	184200	0.0	17435500	0	17435500	126880300
8	7000	31500000	1500000	34600	184200	0.0	17205400	0	17205400	144085700
9	7000	31500000	1500000	34600	184200	0.0	16975300	0	16975300	161061000
10	7000	31500000	1500000	34600	184200	0.0	16745200	0	16745200	177806200
11	5000	22500000	1071400	24700	131600	0.0	14414400	0	14414400	192220600
12	5000	22500000	1071400	24700	131600	0.0	14184300	0	14184300	206404900
13	5000	22500000	1071400	24700	131600	0.0	13954200	0	13954200	220359100
14	5000	22500000	1071400	24700	131600	0.0	13724100	0	13724100	234083200
15	5000	22500000	1071400	24700	131600	0.0	13494000	0	13494000	247577200
16	3500	15750000	750000	17300	92100	0.0	11598900	0	11598900	259176100
17	3500	15750000	750000	17300	92100	0.0	11368900	0	11368900	270545000
18	3500	15750000	750000	17300	92100	0.0	11138800	0	11138800	281683800
19	3500	15750000	750000	17300	92100	0.0	10908700	0	10908700	292592500
20	3500	15750000	750000	17300	92100	0.0	10678600	0	10678600	303271100
21	1500	6750000	321400	7400	39500	0.0	7990500	0	7990500	311261600
22	1500	6750000	321400	7400	39500	0.0	7760400	0	7760400	319022000
23	1500	6750000	321400	7400	39500	0.0	7530300	0	7530300	326552300
24	1500	6750000	321400	7400	39500	0.0	7300300	0	7300300	333852400
25	1500	6750000	321400	7400	39500	0.0	7070200	0	7070200	340922800
26	1500	6750000	321400	7400	39500	0.0	6840100	0	6840100	347762900
27	1500	6750000	321400	7400	39500	0.0	6610000	0	6610000	354372900
28	1500	6750000	321400	7400	39500	0.0	6379900	0	6379900	360752800
29	1500	6750000	321400	7400	39500	0.0	6149800	0	6149800	366902600
30	1500	6750000	321400	7400	39500	0.0	5919800	0	5919800	372822400
TOT	127500	573750000	27321000	630000	3355500		372822400	0	372822400	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							13.65	0.0	13.65	
MILLS PER KILOWATT-HOUR							5.85	0.0	5.85	
CENTS PER MILLION BTU HEAT INPUT							64.98	0.0	64.98	
DOLLARS PER TON OF SULFUR REMOVED							591.78	0.0	591.78	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							132750600	0	132750600	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							12.47	0.0	12.47	
MILLS PER KILOWATT-HOUR							5.34	0.0	5.34	
CENTS PER MILLION BTU HEAT INPUT							59.36	0.0	59.36	
DOLLARS PER TON OF SULFUR REMOVED							540.52	0.0	540.52	

TABLE A-28. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	1,788,000	6.6
Feed preparation (feeders, curshers, ball mills, hoist, tanks, agitators, and pumps)	1,804,000	6.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,323,000	16.0
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	8,930,000	33.2
Stack gas reheat (four indirect steam reheaters)	1,283,000	4.8
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,752,000	6.5
Subtotal	19,880,000	73.8
Services, utilities, and miscellaneous	1,193,000	4.4
Total process areas excluding pond construction	21,073,000	78.2
Pond construction	5,867,000	21.8
Total direct investment	26,940,000	100.0
Indirect Investment		
Engineering design and supervision	1,228,000	4.6
Architect and engineering contractor	270,000	1.0
Construction expense	3,703,000	13.7
Contractor fees	1,173,000	4.4
Total indirect investment	6,374,000	23.7
Contingency	6,663,000	24.7
Total fixed investment	39,977,000	148.4
Other Capital Charges		
Allowance for startup and modifications	3,411,000	12.7
Interest during construction	4,797,000	17.8
Total depreciable investment	48,185,000	178.9
Land	1,175,000	4.4
Working capital	1,077,000	3.9
Total capital investment	50,437,000	187.2

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-29. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	192,000 tons	7.00/ton	1,344,000	9.17
Total raw materials cost			1,344,000	9.17
Conversion costs				
Operating labor and supervision	25,990 man-hr	12.50/man-hr	324,900	2.22
Utilities				
Steam	489,800 MBtu	2.00/MBtu	979,600	6.68
Process water	264,200 kgal	0.12/kgal	31,700	0.22
Electricity	57,197,000 kWh	0.029/kWh	1,658,700	11.32
Maintenance				
Labor and material			1,861,900	12.71
Analyses	3,760 man-hr	17.00/man-hr	63,900	0.44
Total conversion costs			4,920,700	33.59
Total direct costs			6,264,700	42.76
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,891,100	19.73
Average cost of capital and taxes at 8.6% of total capital investment			4,337,600	29.61
Overheads				
Plant, 50% of conversion costs less utilities			1,125,400	7.68
Administrative, 10% of operating labor			32,500	0.22
Total indirect costs			8,386,600	57.24
Total average annual revenue requirements			14,651,300	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	4.19	9.77	0.47	358.22

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a. Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- S removed, 40,900 short tons/yr; solids disposal 215,250 tons/yr Ca solids including only hydrate water.
- Investment and revenue requirement for removal and disposal of flyash excluded.
- Total direct investment, $26,940,000; total depreciable investment, $48,185,000; and total capital investment, $50,437,000.

TABLE A-30

LIMESTONE SLURRY PROCESS 500 MW NEW COAL-FIRED POWER UNIT 3.5% S 90% REMOVAL REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 50437000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	40900	215300	0.0	18989300	0	18989300	18989300
2	7000	31500000	1500000	40900	215300	0.0	18713000	0	18713000	37702300
3	7000	31500000	1500000	40900	215300	0.0	18436700	0	18436700	56139000
4	7000	31500000	1500000	40900	215300	0.0	18160500	0	18160500	74299500
5	7000	31500000	1500000	40900	215300	0.0	17884200	0	17884200	92183700
6	7000	31500000	1500000	40900	215300	0.0	17607900	0	17607900	109791600
7	7000	31500000	1500000	40900	215300	0.0	17331700	0	17331700	127123300
8	7000	31500000	1500000	40900	215300	0.0	17055400	0	17055400	144178700
9	7000	31500000	1500000	40900	215300	0.0	16779100	0	16779100	160957800
10	7000	31500000	1500000	40900	215300	0.0	16502900	0	16502900	177460700
11	5000	22500000	1071400	29200	153800	0.0	14397800	0	14397800	191858500
12	5000	22500000	1071400	29200	153800	0.0	14121500	0	14121500	205980000
13	5000	22500000	1071400	29200	153800	0.0	13845300	0	13845300	219825300
14	5000	22500000	1071400	29200	153800	0.0	13569000	0	13569000	233394300
15	5000	22500000	1071400	29200	153800	0.0	13292700	0	13292700	246687000
16	3500	15750000	750000	20500	107600	0.0	11589100	0	11589100	258276100
17	3500	15750000	750000	20500	107600	0.0	11312800	0	11312800	269588900
18	3500	15750000	750000	20500	107600	0.0	11036500	0	11036500	280625400
19	3500	15750000	750000	20500	107600	0.0	10760300	0	10760300	291385700
20	3500	15750000	750000	20500	107600	0.0	10484000	0	10484000	301869700
21	1500	6750000	321400	8800	46100	0.0	8156600	0	8156600	310026300
22	1500	6750000	321400	8800	46100	0.0	7880400	0	7880400	317906700
23	1500	6750000	321400	8800	46100	0.0	7604100	0	7604100	325510800
24	1500	6750000	321400	8800	46100	0.0	7327800	0	7327800	332838600
25	1500	6750000	321400	8800	46100	0.0	7051600	0	7051600	339890200
26	1500	6750000	321400	8800	46100	0.0	6775300	0	6775300	346665500
27	1500	6750000	321400	8800	46100	0.0	6499000	0	6499000	353164500
28	1500	6750000	321400	8800	46100	0.0	6222800	0	6222800	359387300
29	1500	6750000	321400	8800	46100	0.0	5946500	0	5946500	365333800
30	1500	6750000	321400	8800	46100	0.0	5670200	0	5670200	371004000
TOT	127500	573750000	27321000	745500	3921000		371004000	0	371004000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							13.58	0.0	13.58	
MILLS PER KILOWATT-HOUR							5.82	0.0	5.82	
CENTS PER MILLION BTU HEAT INPUT							64.66	0.0	64.66	
DOLLARS PER TON OF SULFUR REMOVED							497.66	0.0	497.66	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							132602400	0	132602400	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							12.45	0.0	12.45	
MILLS PER KILOWATT-HOUR							5.34	0.0	5.34	
CENTS PER MILLION BTU HEAT INPUT							59.29	0.0	59.29	
DOLLARS PER TON OF SULFUR REMOVED							456.62	0.0	456.62	

TABLE A-31. LIMESTONE SLURRY PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW existing oil-fired power unit, 2.5% S in oil; 0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevators, bins, shaker, puller)	1,077,000	5.3
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,196,000	5.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,447,000	21.9
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	8,377,000	41.3
Stack gas reheat (four direct oil reheaters)	726,000	3.6
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,399,000	6.9
Subtotal	17,222,000	84.9
Services, utilities, and miscellaneous	1,033,000	5.1
Total process areas excluding pond construction	18,255,000	90.0
Pond construction	2,020,000	10.0
Total direct investment	20,275,000	100.0
Indirect Investment		
Engineering design and supervision	1,101,000	5.4
Architect and engineering contractor	257,000	1.3
Construction expense	3,018,000	14.8
Contractor fees	945,000	4.7
Total indirect investment	5,321,000	26.2
Contingency	5,119,000	25.3
Total fixed investment	30,715,000	151.5
Other Capital Charges		
Allowance for startup and modifications	2,870,000	14.2
Interest during construction	3,686,000	18.1
Total depreciable investment	37,271,000	183.8
Land	409,000	2.0
Working capital	800,000	4.0
Total capital investment	38,480,000	189.8

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by direct oil-fired reheat.

Minimum in-process storage: only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-32. LIMESTONE SLURRY PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW existing oil-fired power unit,
2.5% S in oil; 0.8 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	62,410 tons	7.00/ton	436,900	3.82
Total raw materials cost			436,900	3.82
Conversion costs				
Operating labor and supervision	24,860 man-hr	12.50/man-hr	310,800	2.72
Utilities				
Fuel oil (No. 6)	2,676,600 gal	0.40/gal	1,070,600	9.35
Process water	174,700 kgal	0.12/kgal	21,000	0.18
Electricity	45,618,000 kWh	0.029/kWh	1,322,900	11.56
Maintenance				
Labor and material			1,541,200	13.46
Analyses	3,590 man-hr	17.00/man-hr	61,000	0.53
Total conversion costs			4,327,500	37.80
Total direct costs			4,764,400	41.62
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			2,385,300	20.84
Average cost of capital and taxes at 8.6% of total capital investment			3,309,300	28.91
Overheads				
Plant, 50% of conversion costs less utilities			956,500	8.36
Administrative, 10% of operating labor			31,100	0.27
Total indirect costs			6,682,200	58.38
Total average annual revenue requirements			11,446,600	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	3.27	2.15	0.35	770.81

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a. Basis

Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 25 yr.
Power unit on-stream time, 7,000 hr/yr.
Oil burned, 5,350,000 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 14,850 short tons/yr; solids disposal 63,030 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $20,275,000; total depreciable investment, $37,271,000; and total capital investment, $38,480,000.

TABLE A-33

LIMESTONE SLURRY PROCESS 500 MW EXISTING OIL-FIRED POWER UNIT 2.5% S IN OIL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 38480000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	5324100	14800	63000	0.0	14755500	0	14755500	14755500
7	7000	32200000	5324100	14800	63000	0.0	14499000	0	14499000	29254500
8	7000	32200000	5324100	14800	63000	0.0	14242600	0	14242600	43497100
9	7000	32200000	5324100	14800	63000	0.0	13986200	0	13986200	57483300
10	7000	32200000	5324100	14800	63000	0.0	13729800	0	13729800	71213100
11	5000	23000000	3802900	10600	45000	0.0	12077300	0	12077300	83290400
12	5000	23000000	3802900	10600	45000	0.0	11820900	0	11820900	95111300
13	5000	23000000	3802900	10600	45000	0.0	11564400	0	11564400	106675700
14	5000	23000000	3802900	10600	45000	0.0	11308000	0	11308000	117983700
15	5000	23000000	3802900	10600	45000	0.0	11051600	0	11051600	129035300
16	3500	16100000	2662000	7400	31500	0.0	9701000	0	9701000	138736300
17	3500	16100000	2662000	7400	31500	0.0	9444600	0	9444600	148180900
18	3500	16100000	2662000	7400	31500	0.0	9188100	0	9188100	157369000
19	3500	16100000	2662000	7400	31500	0.0	8931700	0	8931700	166300700
20	3500	16100000	2662000	7400	31500	0.0	8675300	0	8675300	174976000
21	1500	6900000	1140900	3200	13500	0.0	6835500	0	6835500	181811500
22	1500	6900000	1140900	3200	13500	0.0	6579100	0	6579100	188390600
23	1500	6900000	1140900	3200	13500	0.0	6322700	0	6322700	194713300
24	1500	6900000	1140900	3200	13500	0.0	6066200	0	6066200	200779500
25	1500	6900000	1140900	3200	13500	0.0	5809800	0	5809800	206589300
26	1500	6900000	1140900	3200	13500	0.0	5553400	0	5553400	212142700
27	1500	6900000	1140900	3200	13500	0.0	5297000	0	5297000	217439700
28	1500	6900000	1140900	3200	13500	0.0	5040600	0	5040600	222480300
29	1500	6900000	1140900	3200	13500	0.0	4784200	0	4784200	227264500
30	1500	6900000	1140900	3200	13500	0.0	4527700	0	4527700	231792200
TOT	92500	425500000	70354000	196000	832500		231792200	0	231792200	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							3.29	0.0	3.29	
MILLS PER KILOWATT-HOUR							5.01	0.0	5.01	
CENTS PER MILLION BTU HEAT INPUT							54.48	0.0	54.48	
DOLLARS PER TON OF SULFUR REMOVED							1182.61	0.0	1182.61	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							94271900	0	94271900	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							2.96	0.0	2.96	
MILLS PER KILOWATT-HOUR							4.50	0.0	4.50	
CENTS PER MILLION BTU HEAT INPUT							48.89	0.0	48.89	
DOLLARS PER TON OF SULFUR REMOVED							1062.82	0.(	1062.82	

TABLE A-34. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(200-MW existing coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	961,000	7.3
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	550,000	4.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts, and dampers from absorber to reheater and stack)	2,141,000	16.3
SO_2 absorption (two tray towers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	4,354,000	33.1
Stack gas reheat (two indirect steam reheaters)	584,000	4.4
Reaction (tanks, agitators, and pumps)	238,000	1.8
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyors)	1,555,000	11.8
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	891,000	6.8
Subtotal	11,274,000	85.7
Services, utilities, and miscellaneous	676,000	5.2
Total process areas excluding pond construction	11,950,000	90.9
Pond construction	1,197,000	9.1
Total direct investment	13,147,000	100.0
Indirect Investment		
Engineering design and supervision	1,099,000	8.4
Architect and engineering contractor	262,000	2.0
Construction expense	2,111,000	16.1
Contractor fees	680,000	5.1
Total indirect investment	4,152,000	31.6
Contingency	3,460,000	26.3
Total fixed investment	20,759,000	157.9
Other Capital Charges		
Allowance for startup and modifications	1,956,000	14.9
Interest during construction	2,491,000	18.9
Total depreciable investment	25,206,000	191.7
Land	243,000	1.8
Working capital	557,000	4.3
Total capital investment	26,006,000	197.8

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-35. GENERIC DOUBLE-ALKALI PROCESS
SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(200-MW existing coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	26,850 tons	42.00/ton	1,127,700	14.83
Soda ash	2,560 tons	90.00/ton	230,400	3.05
Total raw materials cost			1,358,100	17.98
Conversion costs				
Operating labor and supervision	22,490 man-hr	12.50/man-hr	281,100	3.72
Utilities				
Steam	206,800 MBtu	2.00/MBtu	413,600	5.48
Process water	102,100 kgal	0.12/kgal	12,300	0.16
Electricity	12,270,000 kWh	0.031/kWh	380,400	5.04
Maintenance				
Labor and material			580,600	7.69
Analyses	2,630 man-hr	17.00/man-hr	44,700	0.59
Total conversion costs			1,712,700	22.68
Total direct costs			3,070,800	40.66
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 7.0% of total depreciable investment			1,764,400	23.36
Average cost of capital and taxes at 8.6% of total capital investment			2,236,500	29.61
Overheads				
Plant, 50% of conversion costs less utilities			453,200	6.00
Administrative, 10% of operating labor			28,100	0.37
Total indirect costs			4,482,200	59.34
Total average annual revenue requirements			7,553,000	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	5.40	11.92	0.57	511.03

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[a] Basis

Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 20 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 633,500 tons/yr, 9,500 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 14,780 short tons/yr; solids disposal 60,280 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $13,147,000; total depreciable investment, $25,206,000; and total capital investment, $26,006,000.

TABLE A-36

GENERIC DOUBLE ALKALI PROCESS 200 MW EXISTING COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO ECONOMICS

FIXED INVESTMENT: $ 26006000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11	5000	9500000	452400	10600	43100	0.0	8903100	0	8903100	8903100
12	5000	9500000	452400	10600	43100	0.0	8686400	0	8686400	17589500
13	5000	9500000	452400	10600	43100	0.0	8469600	0	8469600	26059100
14	5000	9500000	452400	10600	43100	0.0	8252800	0	8252800	34311900
15	5000	9500000	452400	10600	43100	0.0	8036000	0	8036000	42347900
16	3500	6650000	316700	7400	30100	0.0	7128500	0	7128500	49476400
17	3500	6650000	316700	7400	30100	0.0	6911700	0	6911700	56388100
8	3500	6650000	316700	7400	30100	0.0	6694900	0	6694900	63083000
19	3500	6650000	316700	7400	30100	0.0	6478200	0	6478200	69561200
20	3500	6650000	316700	7400	30100	0.0	6261400	0	6261400	75822600
21	1500	2850000	135700	3200	12900	0.0	5061200	0	5061200	80883800
22	1500	2850000	135700	3200	12900	0.0	4844400	0	4844400	85728200
23	1500	2850000	135700	3200	12900	0.0	4627700	0	4627700	90355900
24	1500	2850000	135700	3200	12900	0.0	4410900	0	4410900	94766800
25	1500	2850000	135700	3200	12900	0.0	4194100	0	4194100	98960900
26	1500	2850000	135700	3200	12900	0.0	3977400	0	3977400	102938300
27	1500	2850000	135700	3200	12900	0.0	3760600	0	3760600	106698900
28	1500	2850000	135700	3200	12900	0.0	3543800	0	3543800	110242700
29	1500	2850000	135700	3200	12900	0.0	3327000	0	3327000	113569700
30	1500	2850000	135700	3200	12900	0.0	3110300	0	3110300	116680000
TOT	57500	109250000	5202500	122000	495000		116680000	0	116680000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							22.43	0.0	22.43	
MILLS PER KILOWATT-HOUR							10.15	0.0	10.15	
CENTS PER MILLION BTU HEAT INPUT							106.80	0.0	106.80	
DOLLARS PER TON OF SULFUR REMOVED							956.39	0.0	956.39	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							53388600	0	53388600	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							20.75	0.0	20.75	
MILLS PER KILOWATT-HOUR							9.39	0.0	9.39	
CENTS PER MILLION BTU HEAT INPUT							98.80	0.0	98.80	
DOLLARS PER TON OF SULFUR REMOVED							885.38	0.0	885.38	

TABLE A-37. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(200-MW new coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	846,000	6.6
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	489,000	3.8
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts, and dampers from absorber to reheater and stack)	1.853,000	14.5
SO_2 absorption (two tray towers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	3,926,000	30.7
Stack gas reheat (two indirect steam reheaters)	569,000	4.5
Reaction (tanks, agitators, and pumps)	209,000	1.6
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	1,375,000	10.8
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	776,000	6.1
Subtotal	10,043,000	78.6
Services, utilities, and miscellaneous	603,000	4.7
Total process areas excluding pond construction	10,646,000	83.3
Pond construction	2,141,000	16.7
Total direct investment	12,787,000	100.0
Indirect Investment		
Engineering design and supervision	1,140,000	8.9
Architect and engineering contractor	266,000	2.1
Construction expense	2,025,000	15.8
Contractor fees	666,000	5.2
Total indirect investment	4,097,000	32.0
Contingency	3,377,000	26.4
Total fixed investment	20,261,000	158.4
Other Capital Charges		
Allowance for startup and modifications	1,812,000	14.2
Interest during construction	2,431,000	19.0
Total depreciable investment	24,504,000	191.6
Land	425,000	3.3
Working capital	548,000	4.3
Total capital investment	25,477,000	199.2

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a. Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-38. GENERIC DOUBLE-ALKALI PROCESS
SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(200-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	26,010 tons	42.00/ton	1,092,400	15.24
Soda ash	2,480 tons	90.00/ton	223,200	3.12
Total raw materials cost			1,315,600	18.36
Conversion costs				
Operating labor and supervision	22,490 man-hr	12.50/man-hr	281,100	3.92
Utilities				
Steam	200,300 MBtu	2.00/MBtu	400,600	5.59
Process water	98,700 kgal	0.12/kgal	11,800	0.16
Electricity	11,880,000 kWh	0.031/kWh	368,300	5.14
Maintenance				
Labor and material			596,500	8.32
Analyses	2,630 man-hr	17.00/man-hr	44,700	0.62
Total conversion costs			1,703,000	23.75
Total direct costs			3,018,600	42.11
Indirect Costs				
Capital charges				
Depreciation, interim replacements and insurance at 6.0% of total depreciable investment			1,470,200	20.51
Average cost of capital and taxes at 8.6% of total capital investment			2,191,000	30.56
Overheads				
Plant, 50% of conversion costs less utilities			461,200	6.43
Administrative, 10% of operating labor			28,100	0.39
Total indirect costs			4,150,500	57.89
Total average revenue requirements			7,169,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	5.12	11.69	0.56	500.99

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a. Basis

Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 613,000 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 14,310 short tons/yr; solids disposal 58,360 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $12,787,000; total depreciable investment, $24,504,000; and total capital investment, $25,477,000.

TABLE A-39

GENERIC DOUBLE ALKALI PROCESS 200 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO ECONOMICS

FIXED INVESTMENT: $ 25477000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	613300	14300	58400	0.0	9360000	0	9360000	9360000
2	7000	12880000	613300	14300	58400	0.0	9219600	0	9219600	18579600
3	7000	12880000	613300	14300	58400	0.0	9079100	0	9079100	27658700
4	7000	12880000	613300	14300	58400	0.0	8938600	0	8938600	36597300
5	7000	12880000	613300	14300	58400	0.0	8798100	0	8798100	45395400
6	7000	12880000	613300	14300	58400	0.0	8657600	0	8657600	54053000
7	7000	12880000	613300	14300	58400	0.0	8517100	0	8517100	62570100
8	7000	12880000	613300	14300	58400	0.0	8376600	0	8376600	70946700
9	7000	12880000	613300	14300	58400	0.0	8236100	0	8236100	79182800
10	7000	12880000	613300	14300	58400	0.0	8095600	0	8095600	87278400
11	5000	9200000	438100	10200	41700	0.0	7081500	0	7081500	94359900
12	5000	9200000	438100	10200	41700	0.0	6941100	0	6941100	101301000
13	5000	9200000	438100	10200	41700	0.0	6800600	0	6800600	108101600
14	5000	9200000	438100	10200	41700	0.0	6660100	0	6660100	114761700
15	5000	9200000	438100	10200	41700	0.0	6519600	0	6519600	121281300
16	3500	6440000	306700	7200	29200	0.0	5699900	0	5699900	126981200
17	3500	6440000	306700	7200	29200	0.0	5559400	0	5559400	132540600
18	3500	6440000	306700	7200	29200	0.0	5418900	0	5418900	137959500
19	3500	6440000	306700	7200	29200	0.0	5278400	0	5278400	143237900
20	3500	6440000	306700	7200	29200	0.0	5137900	0	5137900	148375800
21	1500	2760000	131400	3100	12500	0.0	4028300	0	4028300	152404100
22	1500	2760000	131400	3100	12500	0.0	3887800	0	3887800	156291900
23	1500	2760000	131400	3100	12500	0.0	3747300	0	3747300	160039200
24	1500	2760000	131400	3100	12500	0.0	3606800	0	3606800	163646000
25	1500	2760000	131400	3100	12500	0.0	3466300	0	3466300	167112300
26	1500	2760000	131400	3100	12500	0.0	3325800	0	3325800	170438100
27	1500	2760000	131400	3100	12500	0.0	3185300	0	3185300	173623400
28	1500	2760000	131400	3100	12500	0.0	3044800	0	3044800	176668200
29	1500	2760000	131400	3100	12500	0.0	2904300	0	2904300	179572500
30	1500	2760000	131400	3100	12500	0.0	2763800	0	2763800	182336300
TOT	127500	234600000	11171000	261000	1063500		182336300	0	182336300	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	16.32	0.0	16.32
MILLS PER KILOWATT-HOUR	7.15	0.0	7.15
CENTS PER MILLION BTU HEAT INPUT	77.72	0.0	77.72
DOLLARS PER TON OF SULFUR REMOVED	698.61	0.0	698.61
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	65224800	0	65224800
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	14.98	0.0	14.98
MILLS PER KILOWATT-HOUR	6.56	0.0	6.56
CENTS PER MILLION BTU HEAT INPUT	71.33	0.0	71.33
DOLLARS PER TON OF SULFUR REMOVED	641.98	0.0	641.98

TABLE A-40. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW existing coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	1,927,000	6.7
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	932,000	3.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts, and dampers from absorber to reheater and stack)	5,058,000	17.6
SO_2 absorption (four tray towers including presaturators and entrainment separators, reciruclation tanks, agitators, and pumps)	10,126,000	35.4
Stack gas reheat (four indirect steam reheaters)	1,312,000	4.6
Reaction (tanks, agitators, and pumps)	404,000	1.4
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	2,643,000	9.2
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	1,424,000	5.0
Subtotal	23,826,000	83.2
Services, utilities, and miscellaneous	1,430,000	5.0
Total process areas excluding pond construction	25,256,000	88.2
Pond construction	3,377,000	11.8
Total direct investment	28,633,000	100.0
Indirect Investment		
Engineering design and supervision	1,416,000	5.0
Architect and engineering contractor	328,000	1.1
Construction expense	4,004,000	14.0
Contractor fees	1,229,000	4.3
Total indirect investment	6,977,000	24.4
Contingency	7,122,000	24.8
Total fixed investment	42,732,000	149.2
Other Capital Charges		
Allowance for startup and modifications	3,936,000	13.8
Interest during construction	5,128,000	17.9
Total depreciable investment	51,796,000	180.9
Land	678,000	2.4
Working capital	1,201,000	4.2
Total capital investment	53,675,000	187.5

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-41. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW existing coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	65,010 tons	42.00/ton	2,730,400	17.68
Soda ash	6,190 tons	90.00/ton	557,100	3.61
Total raw materials cost			3,287,500	21.29
Conversion costs				
Operating labor and supervision	34,500 man-hr	12.50/man-hr	431,300	2.79
Utilities				
Steam	500,700 MBtu	2.00/MBtu	1,001,400	6.49
Process water	247,000 kgal	0.12/gal	29,600	0.19
Electricity	29,700,000 kWh	0.029/kWh	861,300	5.58
Maintenance				
Labor and material			1,016,400	6.58
Analyses	4,560 man-hr	17.00/man-hr	77,500	0.50
Total conversion costs			3,417,500	22.13
Total direct costs			6,705,000	43.42
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			3,314,900	21.47
Average cost of capital and taxes at 8.6% of total capital investment			4,616,100	29.89
Overheads				
Plant, 50% of conversion costs less utilities			762,600	4.94
Administrative, 10% of operating labor			43,100	0.28
Total indirect costs			8,736,700	56.58
Total average annual revenue requirements			15,441,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	4.41	10.07	0.48	431.57

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 25 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,533,350 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 35,780 short tons/yr; solids disposal 145,931 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $28,633,000; total depreciable investment, $51,796,000; and total capital investment, $53,675,000.

TABLE A-42

GENERIC DOUBLE ALKALI PROCESS 500 MW EXISTING COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 53675000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1533300	35800	145900	0.0	20058100	0	20058100	20058100
7	7000	32200000	1533300	35800	145900	0.0	19701800	0	19701800	39759900
8	7000	32200000	1533300	35800	145900	0.0	19345400	0	19345400	59105300
9	7000	32200000	1533300	35800	145900	0.0	18989100	0	18989100	78094400
10	7000	32200000	1533300	35800	145900	0.0	18632700	0	18632700	96727100
11	5000	23000000	1095200	25600	104200	0.0	16333300	0	16333300	113060400
12	5000	23000000	1095200	25600	104200	0.0	15976900	0	15976900	129037300
13	5000	23000000	1095200	25600	104200	0.0	15620600	0	15620600	144657900
14	5000	23000000	1095200	25600	104200	0.0	15264200	0	15264200	159922100
15	5000	23000000	1095200	25600	104200	0.0	14907900	0	14907900	174830000
16	3500	16100000	766700	17900	73000	0.0	13056000	0	13056000	187886000
17	3500	16100000	766700	17900	73000	0.0	12699700	0	12699700	200585700
18	3500	16100000	766700	17900	73000	0.0	12343300	0	12343300	212929000
19	3500	16100000	766700	17900	73000	0.0	11987000	0	11987000	224916000
20	3500	16100000	766700	17900	73000	0.0	11630600	0	11630600	236546600
21	1500	6900000	328600	7700	31300	0.0	9180300	0	9180300	245726900
22	1500	6900000	328600	7700	31300	0.0	8823900	0	8823900	254550800
23	1500	6900000	328600	7700	31300	0.0	8467600	0	8467600	263018400
24	1500	6900000	328600	7700	31300	0.0	8111200	0	8111200	271129600
25	1500	6900000	328600	7700	31300	0.0	7754900	0	7754900	278884500
26	1500	6900000	328600	7700	31300	0.0	7398500	0	7398500	286283000
27	1500	6900000	328600	7700	31300	0.0	7042200	0	7042200	293325200
28	1500	6900000	328600	7700	31300	0.0	6685800	0	6685800	300011000
29	1500	6900000	328600	7700	31300	0.0	6329500	0	6329500	306340500
30	1500	6900000	328600	7700	31300	0.0	5973100	0	5973100	312313600
TOT	92500	425500000	20262000	473500	1928500		312313600	0	312313600	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							15.41	0.0	15.41	
MILLS PER KILOWATT-HOUR							6.75	0.0	6.75	
CENTS PER MILLION BTU HEAT INPUT							73.40	0.0	73.40	
DOLLARS PER TON OF SULFUR REMOVED							659.59	0.0	659.59	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							127562500	0	127562500	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							13.89	0.0	13.89	
MILLS PER KILOWATT-HOUR							6.09	0.0	6.09	
CENTS PER MILLION BTU HEAT INPUT							66.16	0.0	66.16	
DOLLARS PER TON OF SULFUR REMOVED							594.97	0.0	594.97	

TABLE A-43. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit,
2.0% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	929,000	4.2
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	524,000	2.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,248,000	19.2
SO_2 absorption (four tray towers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,206,000	41.6
Stack gas reheat (four indirect steam reheaters)	1,222,000	5.5
Reaction (tanks, agitators, and pumps)	224,000	1.0
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	1,476,000	6.7
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	826,000	3.7
Subtotal	18,655,000	84.3
Services, utilities, and miscellaneous	1,119,000	5.1
Total process areas excluding pond construction	19,774,000	89.4
Pond construction	2,339,000	10.6
Total direct investment	22,113,000	100.0
Indirect Investment		
Engineering design and supervision	1,378,000	6.2
Architect and engineering contractor	324,000	1.5
Construction expense	3,239,000	14.6
Contractor fees	1,010,000	4.6
Total indirect investment	5,951,000	26.9
Contingency	5,613,000	25.4
Total fixed investment	33,677,000	152.3
Other Capital Charges		
Allowance for startup and modifications	3,134,000	14.2
Interest during construction	4,041,000	18.2
Total depreciable investment	40,852,000	184.7
Land	464,000	2.1
Working capital	794,000	3.6
Total capital investment	42,110,000	190.4

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-44. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit,
2.0% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	29,260 tons	42.00/ton	1,228,900	10.84
Soda ash	2,790 tons	90.00/ton	251,100	2.21
Total raw materials cost			1,480,000	13.05
Conversion costs				
Operating labor and supervision	31,070 man-hr	12.50/man-hr	388,400	3.43
Utilities				
Steam	489,800 MBtu	2.00/MBtu	979,600	8.64
Process water	226,000 kgal	0.12/kgal	27,100	0.24
Electricity	26,130,000 kWh	0.029/kWh	757,800	6.68
Maintenance				
Labor and material			861,100	7.60
Analyses	4,125,man-hr	17.00/man-hr	70,100	0.62
Total conversion costs			3,084,100	27.21
Total direct costs			4,564,100	40.26
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,451,100	21.63
Average cost of capital and taxes at 8.6% of total capital investment			3,621,500	31.95
Overheads				
Plant, 50% of conversion costs less utilities			659,800	5.82
Administrative, 10% of operating labor			38,800	0.34
Total indirect costs			6,771,200	59.74
Total average annual revenue requirements			11,335,300	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	3.24	7.56	0.36	699.71

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 16,200 short tons/yr; solids disposal 66,070 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $22,113,000; total depreciable investment, $40,852,000; and total capital investment, $42,110,000.

TABLE A-45

GENERIC DOUBLE ALKALI PROCESS 500 MW NEW COAL-FIRED POWER UNIT 2.0% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 42110000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	16200	66100	0.0	14956600	0	14956600	14956600
2	7000	31500000	1500000	16200	66100	0.0	14722400	0	14722400	29679000
3	7000	31500000	1500000	16200	66100	0.0	14488200	0	14488200	44167200
4	7000	31500000	1500000	16200	66100	0.0	14254000	0	14254000	58421200
5	7000	31500000	1500000	16200	66100	0.0	14019800	0	14019800	72441000
6	7000	31500000	1500000	16200	66100	0.0	13785600	0	13785600	86226600
7	7000	31500000	1500000	16200	66100	0.0	13551300	0	13551300	99777900
8	7000	31500000	1500000	16200	66100	0.0	13317100	0	13317100	113095000
9	7000	31500000	1500000	16200	66100	0.0	13082900	0	13082900	126177900
10	7000	31500000	1500000	16200	66100	0.0	12848700	0	12848700	139026600
11	5000	22500000	1071400	11600	47200	0.0	11285300	0	11285300	150311900
12	5000	22500000	1071400	11600	47200	0.0	11051100	0	11051100	161363000
13	5000	22500000	1071400	11600	47200	0.0	10816900	0	10816900	172179900
14	5000	22500000	1071400	11600	47200	0.0	10582700	0	10582700	182762600
15	5000	22500000	1071400	11600	47200	0.0	10348400	0	10348400	193111000
16	3500	15750000	750000	8100	33000	0.0	9085000	0	9085000	202196000
17	3500	15750000	750000	8100	33000	0.0	8850800	0	8850800	211046800
18	3500	15750000	750000	8100	33000	0.0	8616600	0	8616600	219663400
19	3500	15750000	750000	8100	33000	0.0	8382400	0	8382400	228045800
20	3500	15750000	750000	8100	33000	0.0	8148200	0	8148200	236194000
21	1500	6750000	321400	3500	14200	0.0	6455100	0	6455100	242649100
22	1500	6750000	321400	3500	14200	0.0	6220900	0	6220900	248870000
23	1500	6750000	321400	3500	14200	0.0	5986600	0	5986600	254856600
24	1500	6750000	321400	3500	14200	0.0	5752400	0	5752400	260609000
25	1500	6750000	321400	3500	14200	0.0	5518200	0	5518200	266127200
26	1500	6750000	321400	3500	14200	0.0	5284000	0	5284000	271411200
27	1500	6750000	321400	3500	14200	0.0	5049800	0	5049800	276461000
28	1500	6750000	321400	3500	14200	0.0	4815600	0	4815600	281276600
29	1500	6750000	321400	3500	14200	0.0	4581400	0	4581400	285858000
30	1500	6750000	321400	3500	14200	0.0	4347200	0	4347200	290205200
TOT	127500	573750000	27321000	295500	1204000					

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   LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST                     290205200         0   290205200
                    DOLLARS PER TON OF COAL BURNED
                    MILLS PER KILOWATT-HOUR                                            10.62       0.0       10.62
                    CENTS PER MILLION BTU HEAT INPUT                                    4.55       0.0        4.55
                    DOLLARS PER TON OF SULFUR REMOVED                                  50.58       0.0       50.58
PROCESS COST DISCOUNTED AT  11.6% TO INITIAL YEAR, DOLLARS                            982.08       0.0      982.08
   LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED   103925200         0   103925200
                                                                                   PROCESS COST OVER LIFE OF POWER UNIT
                    DOLLARS PER TON OF COAL BURNED
                    MILLS PER KILOWATT-HOUR                                             9.76       0.0        9.76
                    CENTS PER MILLION BTU HEAT INPUT                                    4.18       0.0        4.18
                    DOLLARS PER TON OF SULFUR REMOVED                                  46.47       0.0       46.47
                                                                                      902.91       0.0      902.91
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TABLE A-46. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	1,710,000	6.4
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	833,000	3.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,248,000	15.9
SO_2 absorption (four tray towers including presaturator and entrainment separators, recirculation tanks, agitators, and pumps)	9,206,000	34.4
Stack gas reheat (four indirect steam reheaters)	1,282,000	4.8
Reaction (tanks, agitators, and pumps)	357,000	1.3
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	2,352,000	8.8
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	1,247,000	4.7
Subtotal	21,235,000	79.4
Services, utilities, and miscellaneous	1,274,000	4.8
Total process areas excluding pond construction	22,509,000	84.2
Pond construction	4,241,000	15.8
Total direct investment	26,750,000	100.0
Indirect Investment		
Engineering design and supervision	1,444,000	5.4
Architect and engineering contractor	331,000	1.2
Construction expense	3,746,000	14.0
Contractor fees	1,167,000	4.4
Total indirect investment	6,688,000	25.0
Contingency	6,688,000	25.0
Total fixed investment	40,126,000	150.0
Other Capital Charges		
Allowance for startup and modifications	3,589,000	13.4
Interest during construction	4,815,000	18.0
Total depreciable investment	48,530,000	181.4
Land	837,000	3.1
Working capital	1,184,000	4.4
Total capital investment	50,551,000	188.9

[a] Basis
Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-47. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	63,600 tons	42.00/ton	2,671,200	18.20
Soda ash	6,060 tons	90.00/ton	545,400	3.72
Total raw materials cost			3,216,600	21.92
Conversion costs				
Operating labor and supervision	34,500 man-hr	12.50/man-hr	431,300	2.94
Utilities				
Steam	489,800 MBtu	2.00/MBtu	979,600	6.67
Process water	241,500 kgal	0.12/kgal	29,000	0.20
Electricity	29,100,000 kWh	0.029/kWh	843,900	5.75
Maintenance				
Labor and material			1,027,600	7.00
Analyses	4,560 man-hr	17.00/man-hr	77,500	0.53
Total conversion costs			3,388,900	23.09
Total direct costs			6,605,500	45.01
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,911,800	19.84
Average cost of capital and taxes at 8.6% of total capital investment			4,347,400	29.63
Overheads				
Plant, 50% of conversion costs less utilities			768,200	5.23
Administrative, 10% of operating labor			43,100	0.29
Total indirect costs			8,070,500	54.99
Total average annual revenue requirements			14,676,000	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	4.19	9.78	0.47	419.31

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 35,000 short tons/yr; solids disposal 142,750 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $26,750,000; total depreciable investment, $48,530,000; and total capital investment, $50,551,000.

TABLE A-48

GENERIC DOUBLE-ALKALI PROCESS 500 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 50551000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	35000	142700	0.0	19023600	0	19023600	19023600
2	7000	31500000	1500000	35000	142700	0.0	18745300	0	18745300	37768900
3	7000	31500000	1500000	35000	142700	0.0	18467100	0	18467100	56236000
4	7000	31500000	1500000	35000	142700	0.0	18188800	0	18188800	74424800
5	7000	31500000	1500000	35000	142700	0.0	17910600	0	17910600	92335400
6	7000	31500000	1500000	35000	142700	0.0	17632400	0	17632400	109967800
7	7000	31500000	1500000	35000	142700	0.0	17354100	0	17354100	127321900
8	7000	31500000	1500000	35000	142700	0.0	17075900	0	17075900	144397800
9	7000	31500000	1500000	35000	142700	0.0	16797600	0	16797600	161195400
10	7000	31500000	1500000	35000	142700	0.0	16519400	0	16519400	177714800
11	5000	22500000	1071400	25000	102000	0.0	14326600	0	14326600	192041400
12	5000	22500000	1071400	25000	102000	0.0	14048400	0	14048400	206089800
13	5000	22500000	1071400	25000	102000	0.0	13770100	0	13770100	219859900
14	5000	22500000	1071400	25000	102000	0.0	13491900	0	13491900	233351800
15	5000	22500000	1071400	25000	102000	0.0	13213700	0	13213700	246565500
16	3500	15750000	750000	17500	71400	0.0	11461300	0	11461300	258026800
17	3500	15750000	750000	17500	71400	0.0	11183100	0	11183100	269209900
18	3500	15750000	750000	17500	71400	0.0	10904800	0	10904800	280114700
19	3500	15750000	750000	17500	71400	0.0	10626600	0	10626600	290741300
20	3500	15750000	750000	17500	71400	0.0	10348300	0	10348300	301089600
21	1500	6750000	321400	7500	30600	0.0	8003300	0	8003300	309092900
22	1500	6750000	321400	7500	30600	0.0	7725000	0	7725000	316817900
23	1500	6750000	321400	7500	30600	0.0	7446800	0	7446800	324264700
24	1500	6750000	321400	7500	30600	0.0	7168600	0	7168600	331433300
25	1500	6750000	321400	7500	30600	0.0	6890300	0	6890300	338323600
26	1500	6750000	321400	7500	30600	0.0	6612100	0	6612100	344935700
27	1500	6750000	321400	7500	30600	0.0	6333800	0	6333800	351269500
28	1500	6750000	321400	7500	30600	0.0	6055600	0	6055600	357325100
29	1500	6750000	321400	7500	30600	0.0	5777300	0	5777300	363102400
30	1500	6750000	321400	7500	30600	0.0	5499100	0	5499100	368601500
TOT	127500	573750000	27321000	637500	2600000		368601500	0	368601500	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							13.49	0.0	13.49	
MILLS PER KILOWATT-HOUR							5.78	0.0	5.78	
CENTS PER MILLION BTU HEAT INPUT							64.24	0.0	64.24	
DOLLARS PER TON OF SULFUR REMOVED							578.20	0.0	578.20	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							132472900	0	132472900	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							12.44	0.0	12.44	
MILLS PER KILOWATT-HOUR							5.33	0.0	5.33	
CENTS PER MILLION BTU HEAT INPUT							59.23	0.0	59.23	
DOLLARS PER TON OF SULFUR REMOVED							533.09	0.0	533.09	

TABLE A-49. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 5.0% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	2,399,000	7.8
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	1,077,000	3.5
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,248,000	13.9
SO_2 absorption (four tray towers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,206,000	30.1
Stack gas reheat (four indirect steam reheaters)	1,283,000	4.2
Reaction (tanks, agitators, and pumps)	462,000	1.5
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	3,045,000	10.0
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	1,567,000	5.1
Subtotal	23,287,000	76.1
Services, utilities, and miscellaneous	1,397,000	4.6
Total process areas excluding pond construction	24,684,000	80.7
Pond construction	5,905,000	19.3
Total direct investment	30,589,000	100.0
Indirect Investment		
Engineering design and supervision	1,494,000	4.9
Architect and engineering contractor	336,000	1.1
Construction expense	4,146,000	13.6
Contractor fees	1,292,000	4.2
Total indirect investment	7,268,000	23.8
Contingency	7,571,000	24.7
Total fixed investment	45,428,000	148.5
Other Capital Charges		
Allowance for startup and modifications	3,952,000	12.9
Interest during construction	5,451,000	17.9
Total depreciable investment	54,831,000	179.3
Land	1,184,000	3.9
Working capital	1,564,000	5.1
Total capital investment	57,579,000	188.3

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-50. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit,
5.0% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	97,820 tons	42.00/ton	4,108,400	23.16
Soda ash	9,320 tons	90.00/ton	838,800	4.73
Total raw materials cost			4,947,200	27.89
Conversion costs				
Operating labor and supervision	37,150 man-hr	12.50/man-hr	464,400	2.62
Utilities				
Steam	489,800 MBtu	2.00/MBtu	979,600	5.52
Process water	257,000 kgal	0.12/kgal	30,800	0.17
Electricity	31,960,000 kWh	0.029/kWh	926,800	5.22
Maintenance				
Labor and material			1,164,500	6.57
Analyses	4,940 man-hr	17.00/man-hr	84,000	0.47
Total conversion costs			3,650,100	20.57
Total direct costs			8,597,300	48.46
Indirect Costs				
Capital charges				
Depreciation, interim replacements and insurance at 6.0% of total depreciable investment			3,289,900	18.54
Average cost of capital and taxes at 8.6% of total capital investment			4,951,800	27.91
Overheads				
Plant, 50% of conversion costs less utilities			856,500	4.83
Administrative, 10% of operating labor			46,400	0.26
Total indirect ocsts			9,144,600	51.54
Total average annual revenue requirements			17,741,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	5.07	11.83	0.56	327.46

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,000 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 54,180 short tons/yr; solids disposal 221,000 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $30,589,000; total depreciable investment, $54,831,000; and total capital investment, $57,579,000.

TABLE A-51

GENFRIC DOUBLE ALKALI PROCESS 500 MW NEW COAL-FIRED POWER UNIT 5.0% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 57579000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	54200	221000	0.0	22693200	0	22693200	22693200
2	7000	31500000	1500000	54200	221000	0.0	22378800	0	22378800	45072000
3	7000	31500000	1500000	54200	221000	0.0	22064500	0	22064500	67136500
4	7000	31500000	1500000	54200	221000	0.0	21750100	0	21750100	88886600
5	7000	31500000	1500000	54200	221000	0.0	21435700	0	21435700	110322300
6	7000	31500000	1500000	54200	221000	0.0	21121400	0	21121400	131443700
7	7000	31500000	1500000	54200	221000	0.0	20807000	0	20807000	152250700
8	7000	31500000	1500000	54200	221000	0.0	20492600	0	20492600	172743300
9	7000	31500000	1500000	54200	221000	0.0	20178300	0	20178300	192921600
10	7000	31500000	1500000	54200	221000	0.0	19863900	0	19863900	212785500
11	5000	22500000	1071400	38700	157900	0.0	17064300	0	17064300	229849800
12	5000	22500000	1071400	38700	157900	0.0	16750000	0	16750000	246599800
13	5000	22500000	1071400	38700	157900	0.0	16435600	0	16435600	263035400
14	5000	22500000	1071400	38700	157900	0.0	16121300	0	16121300	279156700
15	5000	22500000	1071400	38700	157900	0.0	15806900	0	15806900	294963600
16	3500	15750000	750000	27100	110500	0.0	13585700	0	13585700	308549300
17	3500	15750000	750000	27100	110500	0.0	13271400	0	13271400	321820700
18	3500	15750000	750000	27100	110500	0.0	12957000	0	12957000	334777700
19	3500	15750000	750000	27100	110500	0.0	12642600	0	12642600	347420300
20	3500	15750000	750000	27100	110500	0.0	12328300	0	12328300	359748600
21	1500	6750000	321400	11600	47400	0.0	9358100	0	9358100	369106700
22	1500	6750000	321400	11600	47400	0.0	9043700	0	9043700	378150400
23	1500	6750000	321400	11600	47400	0.0	8729400	0	8729400	386879800
24	1500	6750000	321400	11600	47400	0.0	8415000	0	8415000	395294800
25	1500	6750000	321400	11600	47400	0.0	8100600	0	8100600	403395400
26	1500	6750000	321400	11600	47400	0.0	7786300	0	7786300	411181700
27	1500	6750000	321400	11600	47400	0.0	7471900	0	7471900	418653600
28	1500	6750000	321400	11600	47400	0.0	7157500	0	7157500	425811100
29	1500	6750000	321400	11600	47400	0.0	6843200	0	6843200	432654300
30	1500	6750000	321400	11600	47400	0.0	6528800	0	6528800	439183100
TOT	127500	573750000	27321000	987000	4026000		439183100	0	439183100	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							16.07	0.0	16.07	
MILLS PER KILOWATT-HOUR							6.89	0.0	6.89	
CENTS PER MILLION BTU HEAT INPUT							76.55	0.0	76.55	
DOLLARS PER TON OF SULFUR REMOVED							444.97	0.0	444.97	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							158278400	0	158278400	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							14.86	0.0	14.86	
MILLS PER KILOWATT-HOUR							6.37	0.0	6.37	
CENTS PER MILLION BTU HEAT INPUT							70.77	0.0	70.77	
DOLLARS PER TON OF SULFUR REMOVED							411.33	0.0	411.33	

TABLE A-52. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(1000-MW existing coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	3,269,000	7.0
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	1,390,000	3.0
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	8,447,000	18.0
SO_2 absorption (four tray towers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	17,207,000	36.7
Stack gas reheat (four indirect steam reheaters)	2,026,000	4.3
Reaction (tanks, agitators, and pumps)	603,000	1.3
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	3,954,000	8.4
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	2,032,000	4.3
Subtotal	38,928,000	83.0
Services, utilities, and miscellaneous	2,336,000	5.0
Total process areas excluding pond construction	41,264,000	88.0
Pond construction	5,636,000	12.0
Total direct investment	46,900,000	100.0
Indirect Investment		
Engineering design and supervision	1,486,000	3.2
Architect and engineering contractor	335,000	0.7
Construction expense	6,027,000	12.8
Contractor fees	1,788,000	3.8
Total indirect investment	9,636,000	20.5
Contingency	11,307,000	24.1
Total fixed investment	67,843,000	144.6
Other Capital Charges		
Allowance for startup and modifications	6,221,000	13.3
Interest during construction	8,141,000	17.4
Total depreciable investment	82,205,000	175.3
Land	1,142,000	2.4
Working capital	2,140,000	4.6
Total capital investment	85,487,000	182.3

[a] Basis
Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-53. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(1000-MW existing coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	127,200 tons	42.00/ton	5,342,400	20.75
Soda ash	12,120 tons	90.00/ton	1,090,800	4.24
Total raw materials cost			6,433,200	24.98
Conversion costs				
Operating labor and supervision	48,150 man-hr	12.50/man-hr	601,900	2.34
Utilities				
Steam	979,700 MBtu	2.00/MBtu	1,959,400	7.61
Process water	483,000 kgal	0.12/kgal	58,000	0.23
Electricity	58,100,000 kWh	0.028/kWh	1,626,800	6.31
Maintenance				
Labor and material			1,277,900	4.96
Analyses	7,080 man-hr	17.00/man-hr	120,400	0.47
Total conversion costs			5,644,400	21.92
Total direct costs			12,077,600	46.90
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			5,261,100	20.43
Average cost of capital and taxes at 8.6% of total capital investment			7,351,900	28.56
Overheads				
Plant, 50% of conversion costs less utilities			1,000,100	3.88
Administrative, 10% of operating labor			60,200	0.23
Total indirect costs			13,673,300	53.10
Total average annual revenue requirements			25,750,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	3.68	8.58	0.41	367.87

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 25 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 2,999,850 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 70,000 short tons/yr; solids disposal 285,500 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $46,900,000; total depreciable investment, $82,205,000; and total capital investment, $85,487,000.

TABLE A-54

GENERIC DOUBLE ALKALI PROCESS 1000 MW EXISTING COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 85487000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	63000000	3000000	70000	285500	0.0	33104800	0	33104800	33104800
7	7000	63000000	3000000	70000	285500	0.0	32539200	0	32539200	65644000
8	7000	63000000	3000000	70000	285500	0.0	31973600	0	31973600	97617600
9	7000	63000000	3000000	70000	285500	0.0	31408100	0	31408100	129025700
10	7000	63000000	3000000	70000	285500	0.0	30842500	0	30842500	159868200
11	5000	45000000	2142900	50000	203900	0.0	26778600	0	26778600	186646800
12	5000	45000000	2142900	50000	203900	0.0	26213000	0	26213000	212859800
13	5000	45000000	2142900	50000	203900	0.0	25647500	0	25647500	238507300
14	5000	45000000	2142900	50000	203900	0.0	25081900	0	25081900	263589200
15	5000	45000000	2142900	50000	203900	0.0	24516300	0	24516300	288105500
16	3500	31500000	1500000	35000	142700	0.0	21279700	0	21279700	309385200
17	3500	31500000	1500000	35000	142700	0.0	20714100	0	20714100	330099300
18	3500	31500000	1500000	35000	142700	0.0	20148500	0	20148500	350247800
19	3500	31500000	1500000	35000	142700	0.0	19582900	0	19582900	369830700
20	3500	31500000	1500000	35000	142700	0.0	19017400	0	19017400	388848100
21	1500	13500000	642900	15000	61200	0.0	14764200	0	14764200	403612300
22	1500	13500000	642900	15000	61200	0.0	14198600	0	14198600	417810900
23	1500	13500000	642900	15000	61200	0.0	13633100	0	13633100	431444000
24	1500	13500000	642900	15000	61200	0.0	13067500	0	13067500	444511500
25	1500	13500000	642900	15000	61200	0.0	12501900	0	12501900	457013400
26	1500	13500000	642900	15000	61200	0.0	11936400	0	11936400	468949800
27	1500	13500000	642900	15000	61200	0.0	11370800	0	11370800	480320600
28	1500	13500000	642900	15000	61200	0.0	10805200	0	10805200	491125800
29	1500	13500000	642900	15000	61200	0.0	10239600	0	10239600	501365400
30	1500	13500000	642900	15000	61200	0.0	9674100	0	9674100	511039500
TOT	92500	832500000	39643500	925000	3772500		511039500	0	511039500	

	TOTAL OP. COST	TOTAL NET SALES REVENUE	NET ANNUAL INCREASE (DECREASE)
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	12.89	0.0	12.89
MILLS PER KILOWATT-HOUR	5.52	0.0	5.52
CENTS PER MILLION BTU HEAT INPUT	61.39	0.0	61.39
DOLLARS PER TON OF SULFUR REMOVED	552.48	0.0	552.48
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	209774100	0	209774100
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	11.68	0.0	11.68
MILLS PER KILOWATT-HOUR	5.00	0.0	5.00
CENTS PER MILLION BTU HEAT INPUT	55.61	0.0	55.61
DOLLARS PER TON OF SULFUR REMOVED	500.53	0.0	500.53

TABLE A-55. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(1000-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	2,873,000	6.7
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	1,234,000	2.8
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	6,651,000	15.5
SO_2 absorption (four tray towers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	15,497,000	36.2
Stack gas reheat (four indirect steam reheaters)	1,875,000	4.4
Reaction (tanks, agitators, and pumps)	530,000	1.2
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	3,493,000	8.1
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	1,769,000	4.1
Subtotal	33,922,000	79.0
Services, utilities, and miscellaneous	2,035,000	4.7
Total process areas excluding pond construction	35,957,000	83.7
Pond construction	7,025,000	16.3
Total direct investment	42,982,000	100.0
Indirect Investment		
Engineering design and supervision	1,525,000	3.5
Architect and engineering contractor	339,000	0.8
Construction expense	5,545,000	12.9
Contractor fees	1,673,000	3.9
Total indirect investment	9,082,000	21.1
Contingency	10,413,000	24.3
Total fixed investment	62,477,000	145.4
Other Capital Charges		
Allowance for startup and modification	5,545,000	12.9
Interest during construction	7,497,000	17.4
Total depreciable investment	75,519,000	175.7
Land	1,412,000	3.3
Working capital	2,085,000	4.8
Total capital investment	79,016,000	183.8

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a. Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-56. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(1000-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	123,000 tons	42.00/ton	5,166,000	21.39
Soda ash	11,720 tons	90.00/ton	1,054,800	4.37
Total raw materials cost			6,220,800	25.76
Conversion costs				
Operating labor and supervision	48,150 man-hr	12.50/man-hr	601,900	2.49
Utilities				
Steam	947,000 MBtu	2.00/MBtu	1,894,000	7.85
Process water	467,000 kgal	0.12/kgal	56,000	0.23
Electricity	56,160,000 kWh	0.028/kWh	1,572,500	6.51
Maintenance				
Labor and material			1,289,500	5.34
Analyses	7,080 man-hr	17.00/man-hr	120,400	0.50
Total conversion costs			5,534,300	22.92
Total direct costs			11,755,100	48.68
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,531,100	18.76
Average cost of capital and taxes at 8.6% of total capital investment			6,795,400	28.14
Overheads				
Plant, 50% of conversion costs less utilities			1,005,900	4.17
Administrative, 10% of operating labor			60,200	0.25
Total indirect costs			12,392,600	51.32
Total average annual revenue requirements			24,147,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	3.45	8.33	0.40	356.84

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 2,900,100 tons/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 67,670 short tons/yr; solids disposal 276,000 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $42,982,000; total depreciable investment, $75,519,000; and total capital investment, $79,016,000.

TABLE A-57

GENERIC DOUBLE ALKALI PROCESS 1000 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL. REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 79016000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2900000	67700	276000	0.0	30943600	0	30943600	30943600
2	7000	60900000	2900000	67700	276000	0.0	30510600	0	30510600	61454200
3	7000	60900000	2900000	67700	276000	0.0	30077600	0	30077600	91531800
4	7000	60900000	2900000	67700	276000	0.0	29644600	0	29644600	121176400
5	7000	60900000	2900000	67700	276000	0.0	29211600	0	29211600	150388000
6	7000	60900000	2900000	67700	276000	0.0	28778700	0	28778700	179166700
7	7000	60900000	2900000	67700	276000	0.0	28345700	0	28345700	207512400
8	7000	60900000	2900000	67700	276000	0.0	27912700	0	27912700	235425100
9	7000	60900000	2900000	67700	276000	0.0	27479700	0	27479700	262904800
10	7000	60900000	2900000	67700	276000	0.0	27046800	0	27046800	289951600
11	5000	43500000	2071400	48300	197200	0.0	23208400	0	23208400	313160000
12	5000	43500000	2071400	48300	197200	0.0	22775400	0	22775400	335935400
13	5000	43500000	2071400	48300	197200	0.0	22342400	0	22342400	358277800
14	5000	43500000	2071400	48300	197200	0.0	21909500	0	21909500	380187300
15	5000	43500000	2071400	48300	197200	0.0	21476500	0	21476500	401663800
16	3500	30450000	1450000	33800	138000	0.0	18441500	0	18441500	420105300
17	3500	30450000	1450000	33800	138000	0.0	18008500	0	18008500	438113800
18	3500	30450000	1450000	33800	138000	0.0	17575600	0	17575600	455689400
19	3500	30450000	1450000	33800	138000	0.0	17142600	0	17142600	472832000
20	3500	30450000	1450000	33800	138000	0.0	16709600	0	16709600	489541600
21	1500	13050000	621400	14500	59100	0.0	12680100	0	12680100	502221700
22	1500	13050000	621400	14500	59100	0.0	12247200	0	12247200	514468900
23	1500	13050000	621400	14500	59100	0.0	11814200	0	11814200	526283100
24	1500	13050000	621400	14500	59100	0.0	11381200	0	11381200	537664300
25	1500	13050000	621400	14500	59100	0.0	10948200	0	10948200	548612500
26	1500	13050000	621400	14500	59100	0.0	10515300	0	10515300	559127800
27	1500	13050000	621400	14500	59100	0.0	10082300	0	10082300	569210100
28	1500	13050000	621400	14500	59100	0.0	9649300	0	9649300	578859400
29	1500	13050000	621400	14500	59100	0.0	9216300	0	9216300	588075700
30	1500	13050000	621400	14500	59100	0.0	8783400	0	8783400	596859100
TOT	127500	1109250000	52821000	1232500	5027000		596859100	0	596859100	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	11.30	0.0	11.30
MILLS PER KILOWATT-HOUR	4.68	0.0	4.68
CENTS PER MILLION BTU HEAT INPUT	53.81	0.0	53.81
DOLLARS PER TON OF SULFUR REMOVED	484.27	0.0	484.27
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	215525300	0	215525300
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	10.47	0.0	10.47
MILLS PER KILOWATT-HOUR	4.34	0.0	4.34
CENTS PER MILLION BTU HEAT INPUT	49.85	0.0	49.85
DOLLARS PER TON OF SULFUR REMOVED	448.54	0.0	448.54

TABLE A-58. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED FIXED INVESTMENT[a]

(500-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; trucking alternative)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	1,710,000	8.1
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	833,000	3.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts, and dampers from absorber to reheater and stack)	4,248,000	20.0
SO_2 absorption (four tray towers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,206,000	43.4
Stack gas reheat (four indirect steam reheaters)	1,282,000	6.1
Reaction (tanks, agitators, and pumps)	357,000	1.7
Solids disposal (thickener, drum filters, tanks, agitators, pumps, and conveyor)	2,352,000	11.1
Subtotal	19,988,000	94.3
Services, utilities, and miscellaneous	1,199,000	5.7
Total direct investment	21,187,000	100.0
Indirect Investment		
Engineering design and supervision	1,175,000	5.5
Architect and engineering contractor	294,000	1.4
Construction expense	3,152,000	14.9
Contractor's fees	977,000	4.6
Total indirect investment	5,598,000	26.4
Contingency	5,357,000	25.3
Total fixed investment	32,142,000	151.7
Other Capital Charges		
Allowance for startup and modifications	3,214.000	15.2
Interest during construction	3,857,000	18.2
Total depreciable investment	39,213,000	185.1
Land	326,000	1.5
Working capital	1,305,000	6.3
Trucking charge (including indirect charges)	491,000	2.3
Total capital investment	41,335,000	195.2

[a] Basis
Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal area located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-59. GENERIC DOUBLE-ALKALI PROCESS
TOTAL AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit,
3.5% S in coal; 1.2 lb SO_2/MBtu
heat input allowable emission; trucking alternative)

Direct Costs	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Raw materials				
Lime	63,600 tons	42.00/ton	2,671,200	18.69
Soda ash	6,060 tons	90.00/ton	545,400	3.81
Total raw material cost			3,216,600	22.50
Conversion costs				
Operating labor and supervision	31,000 man-hr	12.50/man-hr	387,500	2.73
Operating labor disposal equipment	42,000 man-hr	17.00/man-hr	714,000	5.00
Utilities				
Steam	489,800 MBtu	2.00/MBtu	979,600	6.85
Process water	217,600 kgal	0.12/kgal	26,100	6.85
Electricity	27,000,000 kWh	0.029/kWh	783,000	0.18
Fuel	196,000 gal	0.60/gal	117,600	0.82
Maintenance				
Labor and material				5.48
			876,900	6.13
Analyses	5 acres	1600/acre	8,000	0.06
Disposal land preparation	4,180 man-hr	17.00/man-hr	71,100	0.50
Total conversion costs			3,963,800	27.73
Total direct costs			7,180,400	50.23
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,425,800	16.97
Average cost of capital and taxes at 8.6% of total capital investment			3,554,800	24.87
Overheads				
Plant, 50% of conversion costs less utilities			653,100	4.57
Administrative, 10% of operating labor			38,800	0.27
Trucking labor			441,000	3.09
Total indirect costs			7,113,500	49.77
Total annual revenue requirements			14,293,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	4.08	9.53	0.45	408.40

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[a] Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 35,000 short ton/yr; solids disposal 142,750 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $21,187,000; total depreciable investment, $39,213,000, and total capital investment, $41,335,000.

TABLE A-60

GENERIC DOUBLE ALKALI PROCESS 500 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL, TRUCKING ALTERNATIVE, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 41335000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	35000	142700	0.0	17849000	0	17849000	17849000
2	7000	31500000	1500000	35000	142700	0.0	17623600	0	17623600	35472600
3	7000	31500000	1500000	35000	142700	0.0	17398200	0	17398200	52870800
4	7000	31500000	1500000	35000	142700	0.0	17172900	0	17172900	70043700
5	7000	31500000	1500000	35000	142700	0.0	16947500	0	16947500	86991200
6	7000	31500000	1500000	35000	142700	0.0	16722100	0	16722100	103713300
7	7000	31500000	1500000	35000	142700	0.0	16496700	0	16496700	120210000
8	7000	31500000	1500000	35000	142700	0.0	16271300	0	16271300	136481300
9	7000	31500000	1500000	35000	142700	0.0	16045900	0	16045900	152527200
10	7000	31500000	1500000	35000	142700	0.0	15820500	0	15820500	168347700
11	5000	22500000	1071400	25000	102000	0.0	13524100	0	13524100	181871800
12	5000	22500000	1071400	25000	102000	0.0	13298700	0	13298700	195170500
13	5000	22500000	1071400	25000	102000	0.0	13073400	0	13073400	208243900
14	5000	22500000	1071400	25000	102000	0.0	12848000	0	12848000	221091900
15	5000	22500000	1071400	25000	102000	0.0	12622600	0	12622600	233714500
16	3500	15750000	750000	17500	71400	0.0	10789500	0	10789500	244504000
17	3500	15750000	750000	17500	71400	0.0	10564100	0	10564100	255068100
18	3500	15750000	750000	17500	71400	0.0	10338700	0	10338700	265406800
19	3500	15750000	750000	17500	71400	0.0	10113300	0	10113300	275520100
20	3500	15750000	750000	17500	71400	0.0	9887900	0	9887900	285408000
21	1500	6750000	321400	7500	30600	0.0	7372800	0	7372800	292780800
22	1500	6750000	321400	7500	30600	0.0	7147500	0	7147500	299928300
23	1500	6750000	321400	7500	30600	0.0	6922100	0	6922100	306850400
24	1500	6750000	321400	7500	30600	0.0	6696700	0	6696700	313547100
25	1500	6750000	321400	7500	30600	0.0	6471300	0	6471300	320018600
26	1500	6750000	321400	7500	30600	0.0	6245900	0	6245900	326264300
27	1500	6750000	321400	7500	30600	0.0	6020500	0	6020500	332284800
28	1500	6750000	321400	7500	30600	0.0	5795100	0	5795100	338079900
29	1500	6750000	321400	7500	30600	0.0	5569700	0	5569700	343649600
30	1500	6750000	321400	7500	30600	0.0	5344300	0	5344300	348993900
TOT	127500	573750000	27321000	637500	2600000		348993900	0	348993900	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							12.77	0.0	12.77	
MILLS PER KILOWATT-HOUR							5.47	0.0	5.47	
CENTS PER MILLION BTU HEAT INPUT							60.83	0.0	60.83	
DOLLARS PER TON OF SULFUR REMOVED							547.44	0.0	547.44	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							125275900	0	125275900	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							11.76	0.0	11.76	
MILLS PER KILOWATT-HOUR							5.04	0.0	5.04	
CENTS PER MILLION BTU HEAT INPUT							56.02	0.0	56.02	
DOLLARS PER TON OF SULFUR REMOVED							504.13	0.0	504.13	

TABLE A-61. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 3.5% S in coal; 90% SO_2 removal; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	1,889,000	6.8
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	897,000	3.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,248,000	15.3
SO_2 absorption (four tray towers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,206,000	33.2
Stack gas reheat (four indirect steam reheaters)	1,283,000	4.6
Reaction (tanks, agitators, and pumps)	385,000	1.4
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	2,536,000	9.1
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	1,333,000	4.8
Subtotal	21,777,000	78.4
Services, utilities, and miscellaneous	1,307,000	4.7
Total process areas excluding pond construction	23,084,000	83.1
Pond construction	4,679,000	16.9
Total direct investment	27,763,000	100.0
Indirect Investment		
Engineering design and supervision	1,458,000	5.3
Architect and engineering contractor	332,000	1.2
Construction expense	3,852,000	13.9
Contractor fees	1,200,000	4.3
Total indirect investment	6,842,000	24.7
Contingency	6,921,000	24.9
Total fixed investment	41,526,000	149.6
Other Capital Charges		
Allowance for startup and modifications	3,685,000	13.3
Interest during construction	4,983,000	17.9
Total depreciable investment	50,194,000	180.8
Land	932,000	3.4
Working capital	1,278,000	4.6
Total capital investment	52,404,000	188.8

[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-62. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS -

REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	72,450 tons	42.00/ton	3,042,900	19.71
Soda ash	6,900 tons	90.00/ton	621,000	4.02
Total raw materials cost			3,663,900	23.73
Conversion costs				
Operating labor and supervision	34,500 man-hr	12.50/man-hr	431,300	2.79
Utilities				
Steam	489,800 MBtu	2.00/MBtu	979,600	6.34
Process water	245,300 kgal	0.12/kgal	29,400	0.19
Electricity	29,161,000 kWh	0.029/kWh	845,700	5.48
Maintenance				
Labor and material			1,063,700	6.90
Analyses	4,560 man-hr	17.00/man-hr	77,500	0.50
Total conversion costs			3,427,200	22.20
Total direct costs			7,091,100	45.93
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,011,600	19.51
Average cost of capital and taxes at 8.6% of total capital investment			4,506,700	29.19
Overheads				
Plant, 50% of conversion costs less utilities			786,300	5.09
Administrative, 10% of operating labor			43,100	0.28
Total indirect costs			8,347,700	54.07
Total average annual revenue requirements			15,438,800	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	4.41	10.29	0.49	377.48

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 40,900 short tons/yr; solids disposal 166,810 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $27,763,000; total depreciable investment, $50,194,000; and total capital investment, $52,404,000.

TABLE A-63

GENERIC DOUBLE ALKALI PROCESS 500 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL, 90% REMOVAL REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 52404000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	39800	166800	0.0	19945500	0	19945500	19945500
2	7000	31500000	1500000	39800	166800	0.0	19657700	0	19657700	39603200
3	7000	31500000	1500000	39800	166800	0.0	19369900	0	19369900	58973100
4	7000	31500000	1500000	39800	166800	0.0	19082200	0	19082200	78055300
5	7000	31500000	1500000	39800	166800	0.0	18794400	0	18794400	96849700
6	7000	31500000	1500000	39800	166800	0.0	18506600	0	18506600	115356300
7	7000	31500000	1500000	39800	166800	0.0	18218800	0	18218800	133575100
8	7000	31500000	1500000	39800	166800	0.0	17931100	0	17931100	151506200
9	7000	31500000	1500000	39800	166800	0.0	17643300	0	17643300	169149500
10	7000	31500000	1500000	39800	166800	0.0	17355500	0	17355500	186505000
11	5000	22500000	1071400	28400	119200	0.0	15014400	0	15014400	201519400
12	5000	22500000	1071400	28400	119200	0.0	14726600	0	14726600	216246000
13	5000	22500000	1071400	28400	119200	0.0	14438800	0	14438800	230684800
14	5000	22500000	1071400	28400	119200	0.0	14151000	0	14151000	244835800
15	5000	22500000	1071400	28400	119200	0.0	13863300	0	13863300	258699100
16	3500	15750000	750000	19900	83400	0.0	11996300	0	11996300	270695400
17	3500	15750000	750000	19900	83400	0.0	11708500	0	11708500	282403900
18	3500	15750000	750000	19900	83400	0.0	11420700	0	11420700	293824600
19	3500	15750000	750000	19900	83400	0.0	11133000	0	11133000	304957600
20	3500	15750000	750000	19900	83400	0.0	10845200	0	10845200	315802800
21	1500	6750000	321400	8500	35700	0.0	8348000	0	8348000	324150800
22	1500	6750000	321400	8500	35700	0.0	8060300	0	8060300	332211100
23	1500	6750000	321400	8500	35700	0.0	7772500	0	7772500	339983600
24	1500	6750000	321400	8500	35700	0.0	7484700	0	7484700	347468300
25	1500	6750000	321400	8500	35700	0.0	7196900	0	7196900	354665200
26	1500	6750000	321400	8500	35700	0.0	6909200	0	6909200	361574400
27	1500	6750000	321400	8500	35700	0.0	6621400	0	6621400	368195800
28	1500	6750000	321400	8500	35700	0.0	6333600	0	6333600	374529400
29	1500	6750000	321400	8500	35700	0.0	6045800	0	6045800	380575200
30	1500	6750000	321400	8500	35700	0.0	5758100	0	5758100	386333300
TOT	127500	573750000	27321000	724500	3038000		386333300	0	386333300	

	TOTAL OP. COST	TOTAL NET SALES REVENUE	NET ANNUAL INCREASE (DECREASE)
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	14.14	0.0	14.14
MILLS PER KILOWATT-HOUR	6.06	0.0	6.06
CENTS PER MILLION BTU HEAT INPUT	67.33	0.0	67.33
DOLLARS PER TON OF SULFUR REMOVED	533.24	0.0	533.24
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	138947500	0	138947500
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	13.05	0.0	13.05
MILLS PER KILOWATT-HOUR	5.59	0.0	5.59
CENTS PER MILLION BTU HEAT INPUT	62.13	0.0	62.13
DOLLARS PER TON OF SULFUR REMOVED	491.85	0.0	491.85

TABLE A-64. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW existing oil-fired power unit, 2.5% S in oil; 0.8 lb SO_2/MBtu heat input allowable emission; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, bins, and feeders)	995,000	4.7
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	564,000	2.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,398,000	20.9
SO_2 absorption (four tray towers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	8,728,000	41.4
Stack gas reheat (four direct oil reheaters)	726,000	3.4
Reaction (tanks, agitators, and pumps)	243,000	1.2
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	1,596,000	7.6
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	931,000	4.4
Subtotal	18,181,000	86.3
Services, utilities, and miscellaneous	1,091,000	5.2
Total process areas excluding pond construction	19,272,000	91.5
Pond construction	1,794,000	8.5
Total direct investment	21,066,000	100.0
Indirect Investment		
Engineering design and supervision	1,356,000	6.5
Architect and engineering contractor	322,000	1.5
Construction expense	3,125,000	14.8
Contractor fees	973,000	4.6
Total indirect investment	5,776,000	27.4
Contingency	5,368,000	25.5
Total fixed investment	32,210,000	152.9
Other Capital Charges		
Allowance for startup and modifications	3,042,000	14.4
Interest during construction	3,865,000	18.4
Total depreciable investment	39,117,000	185.7
Land	366,000	1.7
Working capital	777,000	3.7
Total capital investment	40,260,000	191.1

a. Basis
Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by direct oil-fired reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for flyash removal and disposal excluded FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-65. GENERIC DOUBLE-ALKALI PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW existing oil-fired power unit,
2.5% S in oil; 0.3 lb SO_2/MBtu
heat input allowable emission; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	28,030 tons	42.00/ton	1,177,300	10.58
Soda ash	2,670 tons	90.00/ton	240,300	2.16
Total raw materials cost			1,417,600	12.74
Conversion costs				
Operating labor and supervision	32,800 man-hr	12.50/man-hr	410,000	3.68
Utilities				
Fuel oil (No. 6)	2,676,600 gal	0.40/gal	1,070,600	9.62
Process water	169,300 kgal	0.12/kgal	20,300	0.18
Electricity	22,410,000 kWh	0.029/kWh	649,900	5.84
Maintenance				
Labor and material			824,700	7.41
Analyses	4,350 man-hr	17.00/man-hr	74,000	0.67
Total conversion costs			3,049,500	27.40
Total direct costs			4,467,100	40.14
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			2,503,500	22.5
Average cost of capital and taxes at 8.6% of total capital investment			3,462,400	31.11
Overheads				
Plant, 50% of conversion costs less utilities			654,400	5.88
Administrative, 10% of operating labor			41,000	0.37
Total indirect costs			6,661,300	59.86
Total average annual revenue requirements			11,128,400	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/short ton S removed
Equivalent unit revenue requirements	3.18	2.09	0.34	749.39

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a. Basis

Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 25 yr.
Power unit on-stream time, 7,000 hr/yr.
Oil burned, 5,324,100 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 14,850 short tons/yr; solids disposal 63,030 tons/yr Ca solids including only hydrate water.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $21,066,000; total depreciable investment, $39,117,000; and total capital investment, $40,260,000.

TABLE A-66

GENERIC DOUBLE ALKALI PROCESS 500 MW EXISTING OIL-FIRED POWER UNIT 2.5% S IN OIL REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 40260000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR DRY SOLIDS	NET REVENUE, $/TON DRY SOLIDS	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	5324100	14800	63000	0.0	14590600	0	14590600	14590600
7	7000	32200000	5324100	14800	63000	0.0	14321500	0	14321500	28912100
8	7000	32200000	5324100	14800	63000	0.0	14052400	0	14052400	42964500
9	7000	32200000	5324100	14800	63000	0.0	13783200	0	13783200	56747700
10	7000	32200000	5324100	14800	63000	0.0	13514100	0	13514100	70261800
11	5000	23000000	3802900	10600	45000	0.0	11943500	0	11943500	82205300
12	5000	23000000	3802900	10600	45000	0.0	11674300	0	11674300	93879600
13	5000	23000000	3802900	10600	45000	0.0	11405200	0	11405200	105284800
14	5000	23000000	3802900	10600	45000	0.0	11136100	0	11136100	116420900
15	5000	23000000	3802900	10600	45000	0.0	10867000	0	10867000	127287900
16	3500	16100000	2662000	7400	31500	0.0	9589800	0	9589800	136877700
17	3500	16100000	2662000	7400	31500	0.0	9320700	0	9320700	146198400
18	3500	16100000	2662000	7400	31500	0.0	9051600	0	9051600	155250000
19	3500	16100000	2662000	7400	31500	0.0	8782500	0	8782500	164032500
20	3500	16100000	2662000	7400	31500	0.0	8513300	0	8513300	172545800
21	1500	6900000	1140900	3200	13500	0.0	6814500	0	6814500	179360300
22	1500	6900000	1140900	3200	13500	0.0	6545400	0	6545400	185905700
23	1500	6900000	1140900	3200	13500	0.0	6276200	0	6276200	192181900
24	1500	6900000	1140900	3200	13500	0.0	6007100	0	6007100	198189000
25	1500	6900000	1140900	3200	13500	0.0	5738000	0	5738000	203927000
26	1500	6900000	1140900	3200	13500	0.0	5468900	0	5468900	209395900
27	1500	6900000	1140900	3200	13500	0.0	5199700	0	5199700	214595600
28	1500	6900000	1140900	3200	13500	0.0	4930600	0	4930600	219526200
29	1500	6900000	1140900	3200	13500	0.0	4661500	0	4661500	224187700
30	1500	6900000	1140900	3200	13500	0.0	4392300	0	4392300	228580000
TOT	92500	425500000	70354000	196000	832500		228580000	0	228580000	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							3.25	0.0	3.25	
MILLS PER KILOWATT-HOUR							4.94	0.0	4.94	
CENTS PER MILLION BTU HEAT INPUT							53.72	0.0	53.72	
DOLLARS PER TON OF SULFUR REMOVED							1166.22	0.0	1166.22	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							93023600	0	93023600	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							2.92	0.0	2.92	
MILLS PER KILOWATT-HOUR							4.44	0.0	4.44	
CENTS PER MILLION BTU HEAT INPUT							48.25	0.0	48.25	
DOLLARS PER TON OF SULFUR REMOVED							1048.74	0.0	1048.74	

TABLE A-67. CITRATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(200-MW existing coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (unloading conveyor, elevator conveyor, pneumatic conveyor, feed storage bins)	417,000	2.2
Feed preparation (feeders, conveyor, tanks, agitator, and pumps)	77,000	0.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	1,824,000	9.6
SO_2 absorption (two packed tower absorbers including presaturators and entrainment separators, strippers, compressor, tanks, agitators, and pumps)	5,512,000	29.0
Stack gas reheat (two indirect steam reheaters)	584,000	3.1
Chloride purge (feeder, tank, agitator, and pumps)	60,000	0.3
SO_2 reduction (reactor tanks, aging tank, agitators, and centrifugal pumps)	661,000	3.5
S separation and removal (flotation tanks, rotary drum filters, pumps, slurry tank, heat exchanger, settling tank, heaters, flash drum, and compressor)	1,599,000	8.4
S storage and shipping (S receiving pit, heaters, S pump, and storage tank)	445,000	2.3
Sulfate purge (coolers, agitators, centrifuge, tanks, pumps, and refrigeration)	544,000	2.9
H_2S generation (battery limit plant)	3,641,000	19.2
H_2 generation (battery limit plant)	2,537,000	13.4
Subtotal	17,901,000	94.3
Services, utilities, and miscellaneous	1,074,000	5.7
Total direct investment	18,975,000	100.0
Indirect Investment		
Engineering design and supervision	2,412,000	12.7
Architect and engineering contractor	603,000	3.2
Construction expense	2,876,000	15.2
Contractor fees	899,000	4.7
Total indirect investment	6,790,000	35.8
Contingency	5,153,000	27.1
Total fixed investment	30,918,000	162.9
Other Capital Charges		
Allowance for startup and modifications	3,092,000	16.3
Interest during construction	3,710,000	19.6
Total depreciable investment	37,720,000	198.8
Land	35,000	0.2
Working capital	1,033,000	5.4
Total capital investment	38,788,000	204.4

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a. Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-63. CITRATE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(200-MW existing coal-fired power unit, 3.5% S in coal;
1.2 lb SO_2/MBtu heat input allowable emission)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	1,210 tons	42.00/ton	50,800	0.41
Soda ash	1,110 tons	90.00/ton	99,900	0.81
Citric acid	96 tons	1,340.00/ton	128,600	1.05
Natural gas	443,000 kft^3	3.50/kft^3	1,550,500	12.62
Catalyst			8,900	0.07
Total raw materials cost			1,838,700	14.96
Conversion costs				
Operating labor and supervision	52,700 man-hr	12.50/man-hr	658,800	5.36
Utilities				
Steam	436,550 MBtu	2.00/MBtu	873,100	7.10
Process water	1,052,000 kgal	0.06/kgal	63,100	0.51
Electricity	27,908,000 kWh	0.031/kWh	865,100	7.04
Maintenance				
Labor and material			1,327,000	10.81
Analyses	5,600 man-hr	17.00/man-hr	95,200	0.77
Total conversion costs			3,882,300	31.59
Total direct costs			5,721,000	46.55
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 7.0% of total depreciable investment			2,640,400	21.48
Average cost of capital and taxes at 8.6% of total capital investment			3,335,800	27.14
Overheads				
Plant, 50% of conversion costs less utilities			1,040,500	8.47
Administrative, 10% of operating labor			65,900	0.54
Marketing, 10% of sales revenue			57,200	0.47
Total indirect costs			7,139,800	58.10
Gross average annual revenue requirements			12,860,800	104.65
Byproduct Sales Revenue				
Sulfur	14,290 short tons	40.00/short ton	(571,600)	(4.65)
Subtotal byproduct sales revenue			(571,600)	(4.65)
Total average annual revenue requirements			12,289,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed	$/short ton S recovered
Equivalent unit revenue requirements	8.78	19.40	0.92	831.47	859.99

a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 20 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 633,500 tons/yr, 9,500 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 14,780 short tons/yr.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $18,975,000; total depreciable investment, $37,720,000; and total capital investment, $38,788,000.

TABLE A-69

CITRATE PROCESS 200 MW EXISTING COAL-FIRED POWER UNIT 3.5% S IN COAL REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 38788000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	NET REVENUE, $/TON SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11	5000	9500000	452400	10600	10200	40.00	14523800	408000	14115800	14115800
12	5000	9500000	452400	10600	10200	40.00	14199400	408000	13791400	27907200
13	5000	9500000	452400	10600	10200	40.00	13875100	408000	13467100	41374300
14	5000	9500000	452400	10600	10200	40.00	13550700	408000	13142700	54517000
15	5000	9500000	452400	10600	10200	40.00	13226300	408000	12818300	67335300
16	3500	6650000	316700	7400	7100	40.00	11593100	284000	11309100	78644400
17	3500	6650000	316700	7400	7100	40.00	11268700	284000	10984700	89629100
18	3500	6650000	316700	7400	7100	40.00	10944300	284000	10660300	100289400
19	3500	6650000	316700	7400	7100	40.00	10619900	284000	10335900	110625300
20	3500	6650000	316700	7400	7100	40.00	10295500	284000	10011500	120636800
21	1500	2850000	135700	3200	3100	40.00	8080500	124000	7956500	128593300
22	1500	2850000	135700	3200	3100	40.00	7756100	124000	7632100	136225400
23	1500	2850000	135700	3200	3100	40.00	7431700	124000	7307700	143533100
24	1500	2850000	135700	3200	3100	40.00	7107300	124000	6983300	150516400
25	1500	2850000	135700	3200	3100	40.00	6782900	124000	6658900	157175300
26	1500	2850000	135700	3200	3100	40.00	6458600	124000	6334600	163509900
27	1500	2850000	135700	3200	3100	40.00	6134200	124000	6010200	169520100
28	1500	2850000	135700	3200	3100	40.00	5809800	124000	5685800	175205900
29	1500	2850000	135700	3200	3100	40.00	5485400	124000	5361400	180567300
30	1500	2850000	135700	3200	3100	40.00	5161000	124000	5037000	185604300
TOT	57500	109250000	5202500	122000	117500		190304300	4700000	185604300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							36.58	0.90	35.68	
MILLS PER KILOWATT-HOUR							16.55	0.41	16.14	
CENTS PER MILLION BTU HEAT INPUT							174.19	4.30	169.89	
DOLLARS PER TON OF SULFUR REMOVED							1559.87	38.52	1521.35	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							87183000	2320500	84862500	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							33.88	0.90	32.98	
MILLS PER KILOWATT-HOUR							15.33	0.41	14.92	
CENTS PER MILLION BTU HEAT INPUT							161.34	4.29	157.05	
DOLLARS PER TON OF SULFUR REMOVED							1445.82	38.48	1407.34	

TABLE A-70. CITRATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(200-MW new coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (unloading conveyor, elevator conveyor, pneumatic conveyor, feed storage bins)	408,000	2.2
Feed preparation (feeders, conveyor, tanks, agitator, and pumps)	75,000	0.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	1,785,000	9.6
SO_2 absorption (two packed tower absorbers including presaturators and entrainment separators, strippers, compressor, tanks, agitators, and pumps)	5,400,000	29.1
Stack gas reheat (two indirect steam reheaters)	569,000	3.1
Chloride purge (feeder, tank, agitator, and pumps)	59,000	0.3
SO_2 reduction (reactor tanks, aging tank, agitators, and centrifugal pumps)	649,000	3.5
S separation and removal (flotation tanks, rotary drum filters, pumps, slurry tank, heat exchanger, settling tank, heaters, flash drum, and compressor)	1,568 000	8.4
S storage and shipping (S receiving pit, heaters, S pump, and storage tank)	436,000	2.3
Sulfate purge (coolers, agitators, centrifuge, tanks, pumps, and refrigeration)	531,000	2.8
H_2S generation (battery limit plant)	3,577,000	19.3
H_2 generation (battery limit plant)	2,480,000	13.3
Subtotal	17,537,000	94.3
Services, utilities, and miscellaneous	1,052,000	5.7
Total direct investment	18,589,000	100.0
Indirect Investment		
Engineering design and supervision	2,394,000	12.9
Architect and engineering contractor	599,000	3.2
Construction expense	2,828,000	15.2
Contractor fees	885,000	4.8
Total indirect investment	6,706,000	36.1
Contingency	5,059,000	27.2
Total fixed investment	30,354,000	163.3
Other Capital Charges		
Allowance for startup and modifications	3,035,000	16.3
Interest during construction	3,643,000	19.6
Total depreciable investment	37,032,000	199.2
Land	35,000	0.2
Working capital	1,008,000	5.4
Total capital investment	38,075,000	204.8

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-71. CITRATE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(200-MW new coal-fired power unit, 3.5% S in coal;
1.2 lb SO_2/MBtu heat input allowable emission)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	1,170 tons	42.00/ton	49,100	0.42
Soda ash	1,070 tons	90.00/ton	96,300	0.83
Citric acid	93 tons	1,340.00/ton	124,600	1.07
Natural gas	429,000 kft^3	3.50/kft^3	1,501,500	12.86
Catalyst			8,600	0.07
Total raw materials cost			1,780,100	15.25
Conversion costs				
Operating labor and supervision	52,700 man-hr	12.50/man-hr	658,800	5.64
Utilities				
Steam	423,600 MBtu	2.00/MBtu	847,200	7.26
Process water	1,019,200 kgal	0.06/kgal	61,200	0.52
Electricity	26,947,000 kWh	0.031/kWh	835,400	7.16
Maintenance				
Labor and material			1,301,200	11.15
Analyses	5,600 man-hr	17.00/man-hr	95,200	0.82
Total conversion costs			3,799,000	32.55
Total direct costs			5,579,100	47.80
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,221,900	19.04
Average cost of capital and taxes at 8.6% of total capital investment			3,274,500	28.07
Overheads				
Plant, 50% of conversion costs less utilities			1,027,600	8.80
Administrative, 10% of operating labor			65,900	0.56
Marketing, 10% of sales revenue			55,400	0.47
Total indirect costs			6,645,300	56.94
Gross average annual revenue requirements			12,224,400	104.74
Byproduct Sales Revenue				
Sulfur	13,840 short tons	40.00/short ton	(553,600)	(4.74)
Subtotal byproduct sales revenue			(553,600)	(4.74)
Total average annual revenue requirements			11,670,800	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed	$/short ton S recovered
Equivalent unit revenue requirements	8.34	19.03	0.91	815.57	843.27

a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 613,200 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 14,310 short tons/yr.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $18,589,000; total depreciable investment, $37,032,000; and total capital investment, $38,075,000.

TABLE A-72

CITRATE PROCESS 200 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 38075000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	NET REVENUE, $/TON SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	613300	14300	13800	40.00	15498800	552000	14946800	14946800
2	7000	12880000	613300	14300	13800	40.00	15286500	552000	14734500	29681300
3	7000	12880000	613300	14300	13800	40.00	15074200	552000	14522200	44203500
4	7000	12880000	613300	14300	13800	40.00	14861800	552000	14309800	58513300
5	7000	12880000	613300	14300	13800	40.00	14649500	552000	14097500	72610800
6	7000	12880000	613300	14300	13800	40.00	14437200	552000	13885200	86496000
7	7000	12880000	613300	14300	13800	40.00	14224900	552000	13672900	100168900
8	7000	12880000	613300	14300	13800	40.00	14012600	552000	13460600	113629500
9	7000	12880000	613300	14300	13800	40.00	13800300	552000	13248300	126877800
10	7000	12880000	613300	14300	13800	40.00	13587900	552000	13035900	139913700
11	5000	9200000	438100	10200	9900	40.00	11744700	396000	11348700	151262400
12	5000	9200000	438100	10200	9900	40.00	11532400	396000	11136400	162398800
13	5000	9200000	438100	10200	9900	40.00	11320100	396000	10924100	173322900
14	5000	9200000	438100	10200	9900	40.00	11107800	396000	10711800	184034700
15	5000	9200000	438100	10200	9900	40.00	10895500	396000	10499500	194534200
16	3500	6440000	306700	7200	6900	40.00	9406400	276000	9130400	203664600
17	3500	6440000	306700	7200	6900	40.00	9194100	276000	8918100	212582700
18	3500	6440000	306700	7200	6900	40.00	8981800	276000	8705800	221288500
19	3500	6440000	306700	7200	6900	40.00	8769500	276000	8493500	229782000
20	3500	6440000	306700	7200	6900	40.00	8557200	276000	8281200	238063200
21	1500	2760000	131400	3100	3000	40.00	6498300	120000	6378300	244441500
22	1500	2760000	131400	3100	3000	40.00	6285900	120000	6165900	250607400
23	1500	2760000	131400	3100	3000	40.00	6073600	120000	5953600	256561000
24	1500	2760000	131400	3100	3000	40.00	5861300	120000	5741300	262302300
25	1500	2760000	131400	3100	3000	40.00	5649000	120000	5529000	267831300
26	1500	2760000	131400	3100	3000	40.00	5436700	120000	5316700	273148000
27	1500	2760000	131400	3100	3000	40.00	5224400	120000	5104400	278252400
28	1500	2760000	131400	3100	3000	40.00	5012000	120000	4892000	283144400
29	1500	2760000	131400	3100	3000	40.00	4799700	120000	4679700	287824100
30	1500	2760000	131400	3100	3000	40.00	4587400	120000	4467400	292291500
TOT	127500	234600000	11171000	261000	252000		302371500	10080000	292291500	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							27.07	0.90	26.17	
MILLS PER KILOWATT-HOUR							11.86	0.40	11.46	
CENTS PER MILLION BTU HEAT INPUT							128.89	4.30	124.59	
DOLLARS PER TON OF SULFUR REMOVED							1158.51	38.62	1119.89	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							108430500	3922200	104508300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							24.90	0.90	24.00	
MILLS PER KILOWATT-HOUR							10.91	0.40	10.51	
CENTS PER MILLION BTU HEAT INPUT							118.57	4.28	114.29	
DOLLARS PER TON OF SULFUR REMOVED							1067.23	38.61	1028.63	

TABLE A-73. CITRATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW existing coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (unloading conveyor, elevator conveyor, pneumatic conveyor, feed storage bins)	782,000	2.1
Feed preparation (feeders, conveyor, tank, agitator, and pumps)	134,000	0.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,154,000	11.1
SO_2 absorption (four packed tower absorbers including presaturators and entrainment separators, strippers, compressor, tanks, agitators, and pumps)	12,459,000	33.3
Stack gas reheat (four indirect steam reheaters)	1,312,000	3.5
Chloride purge (feeder, tank, agitator, and pumps)	98,000	0.3
SO_2 reduction (reactor tanks, aging tank, agitators, and centrifugal pumps)	1,114,000	3.0
S separation and removal (flotation tanks, rotary drum filters, pumps, slurry tank, heat exchanger, settling tank, heaters, flash drum, and compressor)	2,743,000	7.3
S storage and shipping (S receiving pit, heaters, S pump, and storage tank)	783,000	2.1
Sulfate purge (coolers, agitators, centrifuge, tanks, pumps, and refrigeration)	1,009,000	2.7
H_2S generation (battery limit plant)	5,921,000	15.8
H_2 generation (battery limit plant)	4,753,000	12.7
Subtotal	35,262,000	94.3
Services, utilities, and miscellaneous	2,116,000	5.7
Total direct investment	37,378,000	100.0
Indirect Investment		
Engineering design and supervision	3,352,000	9.0
Architect and engineering contractor	838,000	2.2
Construction expense	5,049,000	13.5
Contractor fees	1,505,000	4.0
Total indirect investment	10,744,000	28.7
Contingency	9,624,000	25.8
Total fixed investment	57,746,000	154.5
Other Capital Charges		
Allowance for startup and modifications	5,775,000	15.5
Interest during construction	6,930,000	18.5
Total depreciable investment	70,451,000	188.5
Land	39,000	0.1
Working capital	2,115,000	5.7
Total capital investment	72,605,000	194.3

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[a] Basis
Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-74. CITRATE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW existing coal-fired power unit, 3.5% S in coal;
1.2 lb SO_2/MBtu heat input allowable emission)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	2,930 tons	42.00/ton	123,100	0.53
Soda ash	2,680 tons	90.00/ton	241,200	1.04
Citric acid	233 tons	1,340.00/ton	312,200	1.35
Natural gas	1,070,000 kft^3	3.50/kft^3	3,745,000	16.16
Catalyst			21,600	0.09
Total raw materials cost			4,443,100	19.17
Conversion costs				
Operating labor and supervision	67,920 man-hr	12.50/man-hr	849,000	3.66
Utilities				
Steam	1,059,000 MBtu	2.00/MBtu	2,118,000	9.14
Process water	2,547,800 kgal	0.06/kgal	152,900	0.66
Electricity	67,568,000 kWh	0.029/kWh	1,959,500	8.46
Maintenance				
Labor and material			2,242,700	9.68
Analyses	10,600 man-hr	17.00/man-hr	180,200	0.78
Total conversion costs			7,502,300	32.38
Total direct costs			11,945,400	51.55
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			4,508,900	19.46
Average cost of capital and taxes at 8.6% of total capital investment			6,244,000	26.93
Overheads				
Plant, 50% of conversion costs less utilities			1,636,000	7.06
Administrative, 10% of operating labor			84,900	0.37
Marketing, 10% of sales revenue			138,400	0.60
Total indirect costs			12,612,200	54.42
Gross average annual revenue requirements			24,557,600	105.97
Byproduct Sales Revenue				
Sulfur	34,590 short tons	40.00/short ton	(1,383,600)	(5.97)
Subtotal byproduct sales revenue			(1,383,600)	(5.97)
Total average annual revenue requirements			23,174,000	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed	$/short ton S recovered
Equivalent unit revenue requirements	6.62	15.11	0.72	647.68	669.96

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 25 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,533,350 tons/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 35,780 short tons/yr.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $37,378,000; total depreciable investment, $70,451,000; and total capital investment, $72,605,000.

TABLE A-75

CITRATE PROCESS 500 MW EXISTING COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 72605000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	NET REVENUE, $/TON SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1533300	35800	34600	40.00	30801800	1384000	25417800	25417800
7	7000	32200000	1533300	35800	34600	40.00	30317100	1384000	28933100	58350900
8	7000	32200000	1533300	35800	34600	40.00	29832400	1384000	28448400	86799300
9	7000	32200000	1533300	35800	34600	40.00	29347700	1384000	27963700	114763000
10	7000	32200000	1533300	35800	34600	40.00	28863000	1384000	27479000	142242000
11	5000	23000000	1095200	25600	24700	40.00	24867900	988000	23879900	166121900
12	5000	23000000	1095200	25600	24700	40.00	24383200	988000	23395200	189517100
13	5000	23000000	1095200	25600	24700	40.00	23898500	988000	22910500	212427600
14	5000	23000000	1095200	25600	24700	40.00	23413800	988000	22425800	234853400
15	5000	23000000	1095200	25600	24700	40.00	22929100	988000	21961100	256796500
16	3500	16100000	766700	17900	17300	40.00	19730200	692000	19038200	275832700
17	3500	16100000	766700	17900	17300	40.00	19245500	692000	18553500	294386200
18	3500	16100000	766700	17900	17300	40.00	18760800	692000	18068800	312455000
19	3500	16100000	766700	17900	17300	40.00	18276100	692000	17584100	330035100
20	3500	16100000	766700	17900	17300	40.00	17791600	692000	17099600	362138500
21	1500	6900000	328600	7700	7400	40.00	13473200	296000	13177200	360315700
22	1500	6900000	328600	7700	7400	40.00	12988500	296000	12692500	373008200
23	1500	6900000	328600	7700	7400	40.00	12503800	296000	12207100	385216000
24	1500	6900000	328600	7700	7400	40.00	12019100	296000	11723100	396939100
25	1500	6900000	328600	7700	7400	40.00	11534600	296000	11238600	408177500
26	1500	6900000	328600	7700	7400	40.00	11049700	296000	10753700	418931200
27	1500	6900000	328600	7700	7400	40.00	10565000	296000	10269000	429200200
28	1500	6900000	328600	7700	7400	40.00	10080300	296000	9784300	438984500
29	1500	6900000	328600	7700	7400	40.00	9595700	296000	9299700	448284200
30	1500	6900000	328600	7700	7400	40.00	9111000	296000	8815000	453095200
TOT	92500	425500000	20262000	473500	457000		475379200	18280000	457099200	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							23.46	0.90	22.56	
MILLS PER KILOWATT-HOUR							10.28	0.40	9.88	
CENTS PER MILLION BTU HEAT INPUT							111.72	4.29	107.43	
DOLLARS PER TON OF SULFUR REMOVED							1003.97	38.61	965.36	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							155385100	8285300	187099800	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							21.28	0.90	20.38	
MILLS PER KILOWATT-HOUR							9.32	0.39	8.93	
CENTS PER MILLION BTU HEAT INPUT							101.34	4.30	97.04	
DOLLARS PER TON OF SULFUR REMOVED							911.31	38.64	872.67	

TABLE A-76. CITRATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 2.0% S in coal;
1.2 lb SO_2/MBtu heat input allowable emission)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (unloading conveyor, elevator conveyor, pneumatic conveyor, feed storage bins)	444,000	1.5
Feed preparation (feeders, conveyor, tank, agitator, and pumps)	81,000	0.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,093,000	13.7
SO_2 absorption (four packed tower absorbers including presaturators and entrainment separators, strippers, compressor, tanks, agitators, and pumps)	12,285,000	41.2
Stack gas reheat (four indirect steam reheaters)	1,222,000	4.1
Chloride purge (feeder, tank, agitator, and pumps)	97,000	0.3
SO_2 reduction (reactor tanks, aging tank, agitators, and centrifugal pumps)	696,000	2.3
S separation and removal (flotation tanks, rotary drum filters, pumps, slurry tank, heat exchanger, settling tank, heaters, flash drum, and compressor)	1,685,000	5.6
S storage and shipping (S receiving pit, heaters, S pump, and storage tank)	470,000	1.6
Sulfate purge (coolers, agitators, centrifuge, tanks, pumps, and refrigeration)	577,000	1.9
H_2S generation (battery limit plant)	3,817,000	12.8
H_2 generation (battery limit plant)	2,697,000	9.0
Subtotal	28,164,000	94.3
Services, utilities, and miscellaneous	1,690,000	5.7
Total direct investment	29,854,000	100.0
Indirect Investment		
Engineering design and supervision	2,728,000	9.1
Architect and engineering contractor	682,000	2.3
Construction expense	4,190,000	14.0
Contractor fees	1,268,000	4.2
Total indirect investment	8,868,000	29.6
Contingency	7,744,000	26.0
Total fixed investment	46,466,000	155.6
Other Capital Charges		
Allowance for startup and modifications	4,647,000	15.6
Interest during construction	5,576,000	18.7
Total depreciable investment	56,689,000	189.9
Land	39,000	0.1
Working capital	1,370,000	4.6
Total capital investment	58,098,000	194.6

[a] Basis
Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-77. CITRATE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 2.0% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	1,320 tons	42.00/ton	55,400	0.32
Soda ash	1,210 tons	90.00/ton	108,900	0.64
Citric acid	105 tons	1,340.00/ton	140,700	0.82
Natural gas	483,000 kft^3	3.50/kft^3	1,690,500	9.89
Catalyst			9,700	0.06
Total raw materials cost			2,005,200	11.73
Conversion costs				
Operating labor and supervision	56,380 man-hr	12.50/man-hr	704,800	4.12
Utilities				
Steam	741,500 MBtu	2.00/MBtu	1,483,000	8.68
Process water	1,253,400 kgal	0.06/kgal	75,200	0.44
Electricity	56,355,000 kWh	0.029/kWh	1,634,300	9.56
Maintenance				
Labor and material			1,791,200	10.49
Analyses	9,500 man-hr	17.00/man-hr	161,500	0.94
Total conversion costs			5,850,000	34.23
Total direct costs			7,855,200	45.96
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			3,401,300	19.90
Average cost of capital and taxes at 8.6% of total capital investment			4,996,400	29.24
Overheads				
Plant, 50% of conversion costs less utilities			1,328,800	7.77
Administrative, 10% of operating labor			70,500	0.41
Marketing, 10% of sales revenue			62,300	0.36
Total indirect costs			9,859,300	57.68
Gross average annual revenue requirements			17,714,500	103.64
Byproduct Sales Revenue				
Sulfur	15,570 short tons	40.00/short ton	(622,800)	(3.64)
Subtotal byproduct sales revenue			(622,800)	(3.64)
Total average annual revenue requirements			17,091,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed	$/short ton S recovered
Equivalent unit revenue requirements	4.88	11.39	0.54	1,055.04	1,097.73

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 16,200 short tons/yr.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $29,854,000; total depreciable investment, $56,689,000; and total capital investment, $58,098,000.

TABLE A-78

CITRATE PROCESS 500 MW NEW COAL-FIRED POWER UNIT 2.0% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 58058000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	NET REVENUE, $/TON SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	16200	15600	40.00	22711000	624000	22087000	22087000
2	7000	31500000	1500000	16200	15600	40.00	22385900	624000	21761900	43848900
3	7000	31500000	1500000	16200	15600	40.00	22060900	624000	21436900	65285800
4	7000	31500000	1500000	16200	15600	40.00	21735900	624000	21111900	86397700
5	7000	31500000	1500000	16200	15600	40.00	21410900	624000	20786900	107184600
6	7000	31500000	1500000	16200	15600	40.00	21085900	624000	20461900	127646500
7	7000	31500000	1500000	16200	15600	40.00	20760900	624000	20136900	147783400
8	7000	31500000	1500000	16200	15600	40.00	20435900	624000	19811900	167595300
9	7000	31500000	1500000	16200	15600	40.00	20110900	624000	19486900	187082200
10	7000	31500000	1500000	16200	15600	40.00	19785900	624000	19161900	206244100
11	5000	22500000	1071400	11600	11100	40.00	17150400	444000	16706400	222950500
12	5000	22500000	1071400	11600	11100	40.00	16825400	444000	16381400	239331900
13	5000	22500000	1071400	11600	11100	40.00	16500400	444000	16056400	255388300
14	5000	22500000	1071400	11600	11100	40.00	16175400	444000	15731400	271119700
15	5000	22500000	1071400	11600	11100	40.00	15850400	444000	15406400	286526100
16	3500	15750000	750000	8100	7800	40.00	13726900	312000	13414900	299941000
17	3500	15750000	750000	8100	7800	40.00	13401900	312000	13089900	313030900
18	3500	15750000	750000	8100	7800	40.00	13076900	312000	12764900	325795800
19	3500	15750000	750000	8100	7800	40.00	12751900	312000	12439900	338235700
20	3500	15750000	750000	8100	7800	40.00	12426800	312000	12114800	350350500
21	1500	6750000	321400	3500	3300	40.00	9529500	132000	9397500	359748000
22	1500	6750000	321400	3500	3300	40.00	9204500	132000	9072500	368820500
23	1500	6750000	321400	3500	3300	40.00	8879500	132000	8747500	377568000
24	1500	6750000	321400	3500	3300	40.00	8554500	132000	8422500	385990500
25	1500	6750000	321400	3500	3300	40.00	8229500	132000	8097500	394088000
26	1500	6750000	321400	3500	3300	40.00	7904500	132000	7772500	401860500
27	1500	6750000	321400	3500	3300	40.00	7579500	132000	7447500	409308000
28	1500	6750000	321400	3500	3300	40.00	7254500	132000	7122500	416430500
29	1500	6750000	321400	3500	3300	40.00	6929400	132000	6797400	423227900
30	1500	6750000	321400	3500	3300	40.00	6604400	132000	6472400	429700300
TOT	127500	573750000	27321000	295500	283500		441040300	11340000	429700300	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST			
DOLLARS PER TON OF COAL BURNED	16.14	0.41	15.73
MILLS PER KILOWATT-HOUR	6.92	0.18	6.74
CENTS PER MILLION BTU HEAT INPUT	76.87	1.98	74.89
DOLLARS PER TON OF SULFUR REMOVED	1492.52	38.37	1454.15
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	158411900	4427100	153984800
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT			
DOLLARS PER TON OF COAL BURNED	14.88	0.42	14.46
MILLS PER KILOWATT-HOUR	6.37	0.17	6.20
CENTS PER MILLION BTU HEAT INPUT	70.83	1.98	68.85
DOLLARS PER TON OF SULFUR REMOVED	1376.30	38.47	1337.83

TABLE A-79. CITRATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (unloading conveyor, elevator conveyor, pneumatic conveyor, feed storage bins)	770,000	2.1
Feed preparation (feeders, conveyor, tank, agitator, and pumps)	132,000	0.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,093,000	11.1
SO_2 absorption (four packed tower absorbers including presaturators and entrainment separators, strippers, compressor, tanks, agitators, and pumps)	12,285,000	33.2
Stack gas reheat (four indirect steam reheaters)	1,282,000	3.5
Chloride purge (feeder, tank, agitator, and pumps)	97,000	0.3
SO_2 reduction (reactor tanks, aging tank, agitators, and centrifugal pumps)	1,100,000	3.0
S separation and removal (flotation tanks, rotary drum filters, pumps, slurry tank, heat exchanger, settling tank, heaters, flash drum, and compressor)	2,706,000	7.3
S storage and shipping (S receiving pit, heaters, S pump, and storage tank)	772,000	2.1
Sulfate purge (coolers, agitators, centrifuge, tanks, pumps, and refrigeration)	994,000	2.7
H_2S generation (battery limit plant)	5,850,000	15.9
H_2 generation (battery limit plant)	4,680,000	12.7
Subtotal	34,761,000	94.3
Services, utilities, and miscellaneous	2,086,000	5.7
Total direct investment	36,847,000	100.0
Indirect Investment		
Engineering design and supervision	3,330,000	9.0
Architect and engineering contractor	833,000	2.3
Construction expense	4,989,000	13.5
Contractor fees	1,488,000	4.0
Total indirect investment	10,640,000	28.8
Contingency	9,497,000	25.8
Total fixed investment	56,984,000	154.6
Other Capital Charges		
Allowance for startup and modifications	5,698,000	15.5
Interest during construction	6,838,000	18.6
Total depreciable investment	69,520,000	188.7
Land	39,000	0.1
Working capital	2,080,000	5.6
Total capital investment	71,639,000	194.4

[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-80. CITRATE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 3.5% S in coal;
1.2 lb SO_2/MBtu heat input allowable emission)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	2,870 tons	42.00/ton	120,500	0.53
Soda ash	2,630 tons	90.00/ton	236,700	1.05
Citric acid	230 tons	1,340.00/ton	308,200	1.37
Natural gas	1,050,000 kft³	3.50/kft³	3,675,000	16.31
Catalyst			21,000	0.09
Total raw materials cost			4,361,400	19.35
Conversion costs				
Operating labor and supervision	67,920 man-hr	12.50/man-hr	849,000	3.77
Utilities				
Steam	1,035,900 MBtu	2.00/MBtu	2,071,800	9.19
Process water	2,492,500 kgal	0.06/kgal	149,600	0.66
Electricity	66,100,000 kWh	0.029/kWh	1,916,900	8.51
Maintenance				
Labor and material			2,210,800	9.81
Analyses	10,600 man-hr	17.00/man-hr	180,200	0.80
Total conversion costs			7,378,300	32.74
Total direct costs			11,739,700	52.09
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,171,200	18.51
Average cost of capital and taxes at 8.6% of total capital investment			6,161,000	27.33
Overheads				
Plant, 50% of conversion costs less utilities			1,620,000	7.19
Administrative, 10% of operating labor			84,900	0.38
Marketing, 10% of sales revenue			137,600	0.61
Total indirect costs			12,174,700	54.02
Gross average annual revenue requirements			23,914,400	106.11
Byproduct Sales Revenue				
Sulfur	34,410 short tons	40.00/short ton	(1,376,400)	(6.11)
Subtotal byproduct sales revenue			(1,376,400)	(6.11)
Total average annual revenue requirements			22,538,000	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed	$/short ton S recovered
Equivalent unit revenue requirements	6.44	15.02	0.72	643.94	654.98

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 35,000 short tons/yr.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $36,847,000; total depreciable investment, $69,520,000; and total capital investment, $71,639,000.

TABLE A-81

CITRATE PROCESS 500 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 71639000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	NET REVENUE, $/TON SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	35000	34400	40.00	30075300	1376000	28699300	28699300
2	7000	31500000	1500000	35000	34400	40.00	29676700	1376000	28300700	57000000
3	7000	31500000	1500000	35000	34400	40.00	29278200	1376000	27902200	84902200
4	7000	31500000	1500000	35000	34400	40.00	28879600	1376000	27503600	112405800
5	7000	31500000	1500000	35000	34400	40.00	28481000	1376000	27105000	139510800
6	7000	31500000	1500000	35000	34400	40.00	28082400	1376000	26706400	166217200
7	7000	31500000	1500000	35000	34400	40.00	27683900	1376000	26307900	192525100
8	7000	31500000	1500000	35000	34400	40.00	27285300	1376000	25909300	218434400
9	7000	31500000	1500000	35000	34400	40.00	26886700	1376000	25510700	243945100
10	7000	31500000	1500000	35000	34400	40.00	26488100	1376000	25112100	269057200
11	5000	22500000	1071400	25000	24600	40.00	22639300	984000	21655300	290712500
12	5000	22500000	1071400	25000	24600	40.00	22240700	984000	21256700	311969200
13	5000	22500000	1071400	25000	24600	40.00	21842100	984000	20858100	332827300
14	5000	22500000	1071400	25000	24600	40.00	21443500	984000	20459500	353286800
15	5000	22500000	1071400	25000	24600	40.00	21044900	984000	20060900	373347700
16	3500	15750000	750000	17500	17200	40.00	17978400	688000	17290400	390638100
17	3500	15750000	750000	17500	17200	40.00	17579800	688000	16891800	407529900
18	3500	15750000	750000	17500	17200	40.00	17181200	688000	16493200	424023100
19	3500	15750000	750000	17500	17200	40.00	16782600	688000	16094600	440117700
20	3500	15750000	750000	17500	17200	40.00	16384100	688000	15696100	455813800
21	1500	6750000	321400	7500	7400	40.00	12214200	296000	11918200	467732000
22	1500	6750000	321400	7500	7400	40.00	11815600	296000	11519600	479251600
23	1500	6750000	321400	7500	7400	40.00	11417000	296000	11121000	490372600
24	1500	6750000	321400	7500	7400	40.00	11018500	296000	10722500	501095100
25	1500	6750000	321400	7500	7400	40.00	10619900	296000	10323500	511615000
26	1500	6750000	321400	7500	7400	40.00	10221300	296000	9925300	521344300
27	1500	6750000	321400	7500	7400	40.00	9822700	296000	9526700	530871000
28	1500	6750000	321400	7500	7400	40.00	9424200	296000	9126200	539999200
29	1500	6750000	321400	7500	7400	40.00	9025600	296000	8729600	548728800
30	1500	6750000	321400	7500	7400	40.00	8627000	296000	8331000	557059800
TOT	127500	573750000	27321000	637500	627000		582139800	25080000	557059800	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							21.31	0.92	20.39	
MILLS PER KILOWATT-HOUR							9.13	0.39	8.74	
CENTS PER MILLION BTU HEAT INPUT							101.46	4.37	97.09	
DOLLARS PER TON OF SULFUR REMOVED							913.16	39.34	873.82	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							210134300	9771300	200363000	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							19.73	0.92	18.81	
MILLS PER KILOWATT-HOUR							8.46	0.40	8.06	
CENTS PER MILLION BTU HEAT INPUT							93.96	4.37	89.59	
DOLLARS PER TON OF SULFUR REMOVED							845.61	39.32	806.29	

TABLE A-32. CITRATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 5.0% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (unloading conveyor, elevator conveyor, pneumatic conveyor, feed storage bins)	1,045,000	2.5
Feed preparation (feeders, conveyor, tank, agitator, and pumps)	173,000	0.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,093,000	9.6
SO_2 absorption (four packed tower absorbers including presaturators and entrainment separators, strippers, compressor, tanks, agitators, and pumps)	12,285,000	28.9
Stack gas reheat (four indirect steam reheaters)	1,283,000	3.0
Chloride purge (feeder, tank, agitator, and pumps)	97,000	0.2
SO_2 reduction (reactor tanks, aging tank, agitators, and centrifugal pumps)	1,418,000	3.3
S separation and removal (flotation tanks, rotary drum filters, pumps, slurry tank, heat exchanger, settling tank, heaters, flash drum, and compressor)	3,519,000	8.3
S storage and shipping (S receiving pit, heaters, S pump, and storage tank)	1,017,000	2.4
Sulfate purge (coolers, agitators, centrifuge, tanks, pumps, and refrigeration)	1,344,000	3.2
H_2S generation (battery limit plant)	7,413,000	17.5
H_2 generation (battery limit plant)	6,354,000	15.0
Subtotal	40,041,000	94.3
Services, utilities, and miscellaneous	2,402,000	5.7
Total direct investment	42,443,000	100.0
Indirect Investment		
Engineering design and supervision	3,816,000	9.0
Architect and engineering contractor	954,000	2.2
Construction expense	5,611,000	13.2
Contractor fees	1,657,000	3.9
Total indirect investment	12,038,000	28.3
Contingency	10,896,000	25.7
Total fixed investment	65,377,000	154.0
Other Capital Charges		
Allowance for startup and modifications	6,538,000	15.4
Interest during construction	7,846,000	18.5
Total depreciable investment	79,761,000	187.9
Land	39,000	0.1
Working capital	2,772,000	6.5
Total capital investment	82,572,000	194.5

[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-33. CITRATE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 5.0% S in coal;
1.2 lb SO_2/MBtu heat input allowable emission)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	4,410 tons	42.00/ton	185,200	0.67
Soda ash	4,040 tons	90.00/ton	363,600	1.32
Citric acid	350 tons	1,340.00/ton	469,000	1.70
Natural gas	1,620,000 kft^3	3.50/kft^3	5,670,000	20.61
Catalyst			32,300	0.12
Total raw materials cost			6,720,100	24.42
Conversion costs				
Operating labor and supervision	79,450 man-hr	12.50/man-hr	993,100	3.61
Utilities				
Steam	1,329,800 MBtu	2.00/MBtu	2,659,600	9.67
Process water	3,727,400 kgal	0.06/kgal	223,600	0.81
Electricity	75,814,000 kWh	0.029/kWh	2,198,600	7.99
Maintenance				
Labor and material			2,546,600	9.26
Analyses	11,350 man-hr	17.00/man-hr	193,000	0.70
Total conversion costs			8,814,500	32.04
Total direct costs			15,534,600	56.46
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,785,700	17.39
Average cost of capital and taxes at 8.6% of total capital investment			7,101,200	25.82
Overheads				
Plant, 50% of conversion costs less utilities			1,866,400	6.78
Administrative, 10% of operating labor			99,300	0.36
Marketing, 10% of sales revenue			208,200	0.76
Total indirect costs			14,060,800	51.11
Gross average annual revenue requirements			29,595,400	107.57
Byproduct Sales Revenue				
Sulfur	52,050 short tons	40.00/short ton	(2,082,000)	(7.57)
Subtotal byproduct sales revenue			(2,082,000)	(7.57)
Total average annual revenue requirements			27,513,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed	$/short ton S recovered
Equivalent unit revenue requirements	7.86	18.34	0.87	507.81	528.60

a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 54,180 short tons/yr.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $42,443,000; total depreciable investment, $79,761,000; and total capital investment, $82,572,000.

TABLE A-84

CITRATE PROCESS 500 MW NEW COAL-FIRED POWER UNIT 5.0% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 82572000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	NET REVENUE, $/TON SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	54200	52100	40.00	36696900	2084000	34612900	34612900
2	7000	31500000	1500000	54200	52100	40.00	36239600	2084000	34155600	68768500
3	7000	31500000	1500000	54200	52100	40.00	35782300	2084000	33698300	102466800
4	7000	31500000	1500000	54200	52100	40.00	35325000	2084000	33241000	135707800
5	7000	31500000	1500000	54200	52100	40.00	34867700	2084000	32783700	168491500
6	7000	31500000	1500000	54200	52100	40.00	34410400	2084000	32326400	200817900
7	7000	31500000	1500000	54200	52100	40.00	33953100	2084000	31869100	232687000
8	7000	31500000	1500000	54200	52100	40.00	33495800	2084000	31411800	264098800
9	7000	31500000	1500000	54200	52100	40.00	33038500	2084000	30954500	295053300
10	7000	31500000	1500000	54200	52100	40.00	32581200	2084000	30497200	325550500
11	5000	22500000	1071400	38700	37200	40.00	27561400	1488000	26073400	351623900
12	5000	22500000	1071400	38700	37200	40.00	27104100	1488000	25616100	377240000
13	5000	22500000	1071400	38700	37200	40.00	26646800	1488000	25158800	402398800
14	5000	22500000	1071400	38700	37200	40.00	26189500	1488000	24701500	427100300
15	5000	22500000	1071400	38700	37200	40.00	25732200	1488000	24244200	451344500
16	3500	15750000	750000	27100	26000	40.00	21760300	1040000	20720300	472064800
17	3500	15750000	750000	27100	26000	40.00	21303000	1040000	20263000	492327800
18	3500	15750000	750000	27100	26000	40.00	20845700	1040000	19805700	512133500
19	3500	15750000	750000	27100	26000	40.00	20388400	1040000	19348400	531461900
20	3500	15750000	750000	27100	26000	40.00	19931200	1040000	18891200	550373100
21	1500	6750000	321400	11600	11200	40.00	14540800	448000	14092800	564465900
22	1500	6750000	321400	11600	11200	40.00	14083500	448000	13635500	578101400
23	1500	6750000	321400	11600	11200	40.00	13626200	448000	13178200	591279600
24	1500	6750000	321400	11600	11200	40.00	13168900	448000	12720900	604000500
25	1500	6750000	321400	11600	11200	40.00	12711600	448000	12263600	616264100
26	1500	6750000	321400	11600	11200	40.00	12254300	448000	11806300	628070400
27	1500	6750000	321400	11600	11200	40.00	11797000	448000	11349000	639419400
28	1500	6750000	321400	11600	11200	40.00	11339700	448000	10891700	650311100
29	1500	6750000	321400	11600	11200	40.00	10882400	448000	10434400	660745500
30	1500	6750000	321400	11600	11200	40.00	10425100	448000	9977100	670722600
TOT	127500	573750000	27321000	987000	949000		708682600	37960000	670722600	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							25.94	1.39	24.55	
MILLS PER KILOWATT-HOUR							11.12	0.60	10.52	
CENTS PER MILLION BTU HEAT INPUT							123.52	6.62	116.90	
DOLLARS PER TON OF SULFUR REMOVED							718.02	38.46	679.56	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							256736200	14794700	241941500	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							24.11	1.39	22.72	
MILLS PER KILOWATT-HOUR							10.33	0.59	9.74	
CENTS PER MILLION BTU HEAT INPUT							114.80	6.62	108.18	
DOLLARS PER TON OF SULFUR REMOVED							667.19	38.44	628.75	

TABLE A-35. CITRATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(1000-MW existing coal-fired power unit, 3.5% S in coal;
1.2 lb SO_2/MBtu heat input allowable emission)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (unloading conveyor, elevator conveyor, pneumatic conveyor, feed storage bins)	1,260,000	2.2
Feed preparation (feeders, conveyor, tank, agitator, and pumps)	204,000	0.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	6,557,000	11.4
SO_2 absorption (four packed tower absorbers including presaturators and entrainment separators, strippers, compressor, tanks, agitators, and pumps)	19,144,000	33.4
Stack gas reheat (four indirect steam reheaters)	2,026,000	3.5
Chloride purge (feeder, tank, agitator, and pumps)	143,000	0.2
SO_2 reduction (reactor tanks, aging tank, agitators, and centrifugal pumps)	1,656,000	2.9
S separation and removal (flotation tanks, rotary drum filters, pumps, slurry tank, heat exchanger, settling tank, heaters, flash drum, and compressor)	4,130,000	7.2
S storage and shipping (S receiving pit, heaters, S pump, and storage tank)	1,203,000	2.1
Sulfate purge (coolers, agitators, centrifuge, tanks, pumps, and refrigeration)	1,615,000	2.8
H_2S generation (battery limit plant)	8,565,000	14.9
H_2 generation (battery limit plant)	7,656,000	13.3
Subtotal	54,159,000	94.3
Services, utilities, and miscellaneous	3,250,000	5.7
Total direct investment	57,409,000	100.0
Indirect Investment		
Engineering design and supervision	4,184,000	7.3
Architect and engineering contractor	1,046,000	1.8
Construction expense	7,209,000	12.6
Contractor fees	2,085,000	3.6
Total indirect investment	14,524,000	25.3
Contingency	14,386,000	25.1
Total fixed investment	86,319,000	150.4
Other Capital Charges		
Allowance for startup and modifications	8,632,000	15.0
Interest during construction	10,358,000	18.0
Total depreciable investment	105,309,000	183.4
Land	45,000	0.1
Working capital	3,670,000	6.4
Total capital investment	109,024,000	189.9

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[a] Basis
Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-36. CITRATE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(1000-MW existing coal-fired power unit, 3.5% S in coal;
1.2 lb SO_2/MBtu heat input allowable emission)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	5,730 tons	42.00/ton	240,700	0.65
Soda ash	5,250 tons	90.00/ton	472,500	1.28
Citric acid	455 tons	1,340.00/ton	609,700	1.65
Natural gas	2,100,000 kft³	3.50/kft³	7,350,000	19.91
Catalyst			42,000	0.11
Total raw materials cost			8,714,900	23.60
Conversion costs				
Operating labor and supervision	83,100 man-hr	12.50/man-hr	1,038,800	2.81
Utilities				
Steam	2,062,800 MBtu	2.00/MBtu	4,125,600	11.17
Process water	4,984,900 kgal	0.06/kgal	299,100	0.81
Electricity	132,201,000 kWh	0.028/kWh	3,701,600	10.03
Maintenance				
Labor and material			2,870,500	7.77
Analyses	17,450 man-hr	17.00/man-hr	296,700	0.80
Total conversion costs			12,332,300	33.39
Total direct costs			21,047,200	56.99
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			6,739,800	18.25
Average cost of capital and taxes at 8.6% of total capital investment			9,376,100	25.39
Overheads				
Plant, 50% of conversion costs less utilities			2,103,000	5.69
Administrative, 10% of operating labor			103,900	0.28
Marketing, 10% of sales revenue			270,700	0.73
Total indirect costs			18,593,500	50.34
Gross average annual revenue requirements			39,640,700	107.33
Byproduct Sales Revenue				
Sulfur	67,680 short tons	40.00/short ton	(2,707,200)	(7.33)
Subtotal byproduct sales revenue			(2,707,200)	(7.33)
Total average annual revenue requirements			36,933,500	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed	$/short ton S recovered
Equivalent unit revenue requirements	5.28	12.31	0.59	527.62	545.71

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 25 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 2,999,850 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 70,000 short tons/yr.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $57,409,000; total depreciable investment, $105,309,000; and total capital investment, $109,024,000.

TABLE A-87

CITRATE PROCESS 1000 MW EXISTING COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 109024000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	NET REVENUE, $/TON SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	63000000	3000000	70000	67700	40.00	49016900	2708000	46308900	46308900
7	7000	63000000	3000000	70000	67700	40.00	48292400	2708000	45584400	91893300
8	7000	63000000	3000000	70000	67700	40.00	47567900	2708000	44859900	136753200
9	7000	63000000	3000000	70000	67700	40.00	46843300	2708000	44135300	180888500
10	7000	63000000	3000000	70000	67700	40.00	46118800	2708000	43410800	224299300
11	5000	45000000	2142900	50000	48300	40.00	39200600	1932000	37268600	261567900
12	5000	45000000	2142900	50000	48300	40.00	38476000	1932000	36544000	298111900
13	5000	45000000	2142900	50000	48300	40.00	37751500	1932000	35819500	333931400
14	5000	45000000	2142900	50000	48300	40.00	37027000	1932000	35095000	369026400
15	5000	45000000	2142900	50000	48300	40.00	36302400	1932000	34370400	403396800
16	3500	31500000	1500000	35000	33800	40.00	30833900	1352000	29481900	432878700
17	3500	31500000	1500000	35000	33800	40.00	30109400	1352000	28757400	461636100
18	3500	31500000	1500000	35000	33800	40.00	29384800	1352000	28032800	489668900
19	3500	31500000	1500000	35000	33800	40.00	28660300	1352000	27308300	516977200
20	3500	31500000	1500000	35000	33800	40.00	27935800	1352000	26583800	543561000
21	1500	13500000	642900	15000	14500	40.00	20623600	580000	20043600	563604600
22	1500	13500000	642900	15000	14500	40.00	19899100	580000	19319100	582923700
23	1500	13500000	642900	15000	14500	40.00	19174600	580000	18594600	601518300
24	1500	13500000	642900	15000	14500	40.00	18450000	580000	17870000	619388300
25	1500	13500000	642900	15000	14500	40.00	17725500	580000	17145500	636533800
26	1500	13500000	642900	15000	14500	40.00	17001000	580000	16421000	652954800
27	1500	13500000	642900	15000	14500	40.00	16276400	580000	15696400	668651200
28	1500	13500000	642900	15000	14500	40.00	15551900	580000	14971900	683623100
29	1500	13500000	642900	15000	14500	40.00	14827400	580000	14247400	697870500
30	1500	13500000	642900	15000	14500	40.00	14102800	580000	13522800	711393300
TOT	92500	832500000	39643500	925000	894000		747153300	35760000	711393300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							18.85	0.91	17.94	
MILLS PER KILOWATT-HOUR							8.08	0.39	7.69	
CENTS PER MILLION BTU HEAT INPUT							89.75	4.30	85.45	
DOLLARS PER TON OF SULFUR REMOVED							807.73	38.66	769.07	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							309321200	16207400	293113800	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							17.22	0.90	16.32	
MILLS PER KILOWATT-HOUR							7.38	0.39	6.99	
CENTS PER MILLION BTU HEAT INPUT							82.00	4.30	77.70	
DOLLARS PER TON OF SULFUR REMOVED							738.06	38.67	699.39	

TABLE A-88. CITRATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(1000-MW new coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (unloading conveyor, elevator conveyor, pneumatic conveyor, feed storage bins)	1,230,000	2.2
Feed preparation (feeders, conveyor, tank, agitator, and pumps)	200,000	0.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	6,408,000	11.4
SO_2 absorption (four packed tower absorbers including presaturators and entrainment separators, strippers, compressor, tanks, agitators, and pumps)	18,733,000	33.5
Stack gas reheat (four indirect steam reheaters)	1,875,000	3.3
Chloride purge (feeder, tank, agitator, and pumps)	140,000	0.2
SO_2 reduction (reactor tanks, aging tank, agitators, and centrifugal pumps)	1,623,000	2.9
S separation and removal (flotation tanks, rotary drum filters, pumps, slurry tank, heat exchanger, settling tank, heaters, flash drum, and compressor)	4,045,000	7.2
S storage and shipping (S receiving pit, heaters, S pump, and storage tank)	1,177,000	2.1
Sulfate purge (coolers, agitators, centrifuge, tanks, pumps, and refrigeration)	1,577,000	2.8
H_2S generation (battery limit plant)	8,406,000	15.0
H_2 generation (battery limit plant)	7,473,000	13.3
Subtotal	52,887,000	94.3
Services, utilities, and miscellaneous	3,173,000	5.7
Total direct investment	56,060,000	100.0
Indirect Investment		
Engineering design and supervision	4,132,000	7.4
Architect and engineering contractor	1,033,000	1.8
Construction expense	7,068,000	12.6
Contractor fees	2,048,000	3.7
Total indirect investment	14,281,000	25.5
Contingency	14,068,000	25.1
Total fixed investment	84,409,000	150.6
Other Capital Charges		
Allowance for startup and modifications	8,441,000	15.1
Interest during construction	10,129,000	18.0
Total depreciable investment	102,979,000	183.7
Land	45,000	0.1
Working capital	3,565,000	6.4
Total capital investment	106,589,000	190.2

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-39. CITRATE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(1000-MW new coal-fired power unit, 3.5% S in coal; 1.2 lb SO_2/MBtu heat input allowable emission)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	5,540 tons	42.00/ton	232,700	0.65
Soda ash	5,070 tons	90.00/ton	456,300	1.28
Citric acid	440 tons	1,340.00/ton	589,600	1.66
Natural gas	2,030,000 kft³	3.50/kft³	7,105,000	19.96
Catalyst			40,600	0.11
Total raw materials cost			8,424,200	23.66
Conversion costs				
Operating labor and supervision	83,100 man-hr	12.50/man-hr	1,038,800	2.92
Utilities				
Steam	2,002,700 MBtu	2.00/MBtu	4,005,400	11.26
Process water	4,818,600 kgal	0.06/kgal	289,100	0.81
Electricity	127,919,000 kWh	0.028/kWh	3,581,700	10.06
Maintenance				
Labor and material			2,803,000	7.87
Analyses	17,450 man-hr	17.00/man-hr	296,700	0.83
Total conversion costs			12,014,700	33.75
Total direct costs			20,438,900	57.41
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			6,178,700	17.35
Average cost of capital and taxes at 8.6% of total capital investment			9,166,700	25.75
Overheads				
Plant, 50% of conversion costs less utilities			2,069,300	5.81
Administrative, 10% of operating labor			103,900	0.29
Marketing, 10% of sales revenue			261,700	0.74
Total indirect costs			17,780,300	49.94
Gross average annual revenue requirements			38,219,200	107.35
Byproduct Sales Revenue				
Sulfur	65,420 short tons	40.00/short ton	(2,616,800)	(7.35)
Subtotal byproduct sales revenue			(2,616,800)	(7.35)
Total average annual revenue requirements			35,602,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed	$/short ton S recovered
Equivalent unit revenue requirements	5.09	12.28	0.58	526.12	544.21

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 2,900,100 tons/yr, 8,700 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 67,670 short tons/yr.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $56,060,000; total depreciable investment, $102,979,000; and total capital investment, $106,589,000.

TABLE A-90

CITRATE PROCESS 1000 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL, REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 106589000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	NET REVENUE, $/TON SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2900000	67700	65400	40.00	47385600	2616000	44769600	44769600
2	7000	60900000	2900000	67700	65400	40.00	46795200	2616000	44179200	88948800
3	7000	60900000	2900000	67700	65400	40.00	46204800	2616000	43588800	132537600
4	7000	60900000	2900000	67700	65400	40.00	45614400	2616000	42998400	175536000
5	7000	60900000	2900000	67700	65400	40.00	45024000	2616000	42408000	217944000
6	7000	60900000	2900000	67700	65400	40.00	44433600	2616000	41817600	259761600
7	7000	60900000	2900000	67700	65400	40.00	43843200	2616000	41227200	300988800
8	7000	60900000	2900000	67700	65400	40.00	43252800	2616000	40636800	341625600
9	7000	60900000	2900000	67700	65400	40.00	42662400	2616000	40046400	381672000
10	7000	60900000	2900000	67700	65400	40.00	42071900	2616000	39455900	421127900
11	5000	43500000	2071400	48300	46700	40.00	35466300	1868000	33598300	454726200
12	5000	43500000	2071400	48300	46700	40.00	34875900	1868000	33007900	487734100
13	5000	43500000	2071400	48300	46700	40.00	34285500	1868000	32417500	520151600
14	5000	43500000	2071400	48300	46700	40.00	33695100	1868000	31827100	551978700
15	5000	43500000	2071400	48300	46700	40.00	33104700	1868000	31236700	583215400
16	3500	30450000	1450000	33800	32700	40.00	27905700	1308000	26597700	609813100
17	3500	30450000	1450000	33800	32700	40.00	27315300	1308000	26007300	635820400
18	3500	30450000	1450000	33800	32700	40.00	26724900	1308000	25416900	661237300
19	3500	30450000	1450000	33800	32700	40.00	26134500	1308000	24826500	686063800
20	3500	30450000	1450000	33800	32700	40.00	25544100	1308000	24236100	710299900
21	1500	13050000	621400	14500	14000	40.00	18550300	560000	17990300	728290200
22	1500	13050000	621400	14500	14000	40.00	17959900	560000	17399900	745690100
23	1500	13050000	621400	14500	14000	40.00	17369400	560000	16809400	762499500
24	1500	13050000	621400	14500	14000	40.00	16779000	560000	16219000	778718500
25	1500	13050000	621400	14500	14000	40.00	16188600	560000	15628600	794347100
26	1500	13050000	621400	14500	14000	40.00	15598200	560000	15038200	809385300
27	1500	13050000	621400	14500	14000	40.00	15007800	560000	14447800	823833100
28	1500	13050000	621400	14500	14000	40.00	14417400	560000	13857400	837690500
29	1500	13050000	621400	14500	14000	40.00	13827000	560000	13267000	850957500
30	1500	13050000	621400	14500	14000	40.00	13236600	560000	12676600	863634100
TOT	127500	1109250000	5282100	1232500	1191000		511274100	4764000	863634100	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							17.25	0.90	16.35	
MILLS PER KILOWATT-HOUR							7.15	0.38	6.77	
CENTS PER MILLION BTU HEAT INPUT							82.15	4.29	77.86	
DOLLARS PER TON OF SULFUR REMOVED							739.37	38.65	700.72	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							331089100	18571800	312517300	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							16.08	0.90	15.18	
MILLS PER KILOWATT-HOUR							6.66	0.37	6.29	
CENTS PER MILLION BTU HEAT INPUT							76.57	4.29	72.28	
DOLLARS PER TON OF SULFUR REMOVED							689.05	38.65	650.40	

TABLE A-91. CITRATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 3.5% S in coal; 90% SO_2 removal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (unloading conveyor, elevator conveyor, pneumatic conveyor, feed storage bins)	845,000	2.2
Feed preparation (feeders, conveyor, tank, agitator, and pumps)	143,000	0.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,093,000	10.7
SO_2 absorption (four packed tower absorbers including presaturators and entrainment separators, strippers, compressor, tanks, agitators, and pumps)	12,285,000	31.9
Stack gas reheat (four indirect steam reheaters)	1,283,000	3.3
Chloride purge (feeder, tank, agitator, and pumps)	97,000	0.3
SO_2 reduction (reactor tanks, aging tank, agitators, and centrifugal pumps)	1,188,000	3.1
S separation and removal (flotation tanks, rotary drum filters, pumps, slurry tank, heat exchanger, settling tank, heaters, flash drum, and compressor)	2,930,000	7.6
S storage and shipping (S receiving pit, heaters, S pump, and storage tank)	839,000	2.2
Sulfate purge (coolers, agitators, centrifuge, tanks, pumps, and refrigeration)	1,089,000	2.8
H_2S generation (battery limit plant)	6,285,000	16.4
H_2 generation (battery limit plant)	5,133,000	13.4
Subtotal	36,210,000	94.3
Services, utilities, and miscellaneous	2,173,000	5.7
Total direct investment	38,383,000	100.0
Indirect Investment		
Engineering design and supervision	3,463,000	9.0
Architect and engineering contractor	866,000	2.3
Construction expense	5,161,000	13.4
Contractor fees	1,535,000	4.0
Total indirect investment	11,025,000	28.7
Contingency	9,881,000	25.7
Total fixed investment	59,289,000	154.4
Other Capital Charges		
Allowance for startup and modifications	5,929,000	15.4
Interest during construction	7,115,000	18.6
Total depreciable investment	72,333,000	188.4
Land	39,000	0.1
Working capital	2,252,000	5.9
Total capital investment	74,624,000	194.4

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[a] Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-92. CITRATE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	3,260 tons	42.00/ton	136,900	0.57
Soda ash	2,990 tons	90.00/ton	269,100	1.13
Citric acid	259 tons	1,340.00/ton	347,100	1.46
Natural gas	1,200,000 kft^3	3.50/kft^3	4,200,000	17.64
Catalyst			23,900	0.10
Total raw materials cost			4,977,000	20.90
Conversion costs				
Operating labor and supervision	67,920 man-hr	12.50/man-hr	849,000	3.57
Utilities				
Steam	1,111,900 MBtu	2.00/MBtu	2,223,800	9.33
Process water	2,812,000 kgal	0.06/kgal	168,700	0.71
Electricity	68,613,000 kWh	0.029/kWh	1,989,800	8.36
Maintenance				
Labor and material			2,303,000	9.67
Analyses	10,600 man-hr	17.00/man-hr	180,200	0.76
Total conversion costs			7,714,500	32.40
Total direct costs			12,691,500	53.30
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,340,000	18.23
Average cost of capital and taxes at 8.6% of total capital investment			6,417,700	26.94
Overheads				
Plant, 50% of conversion costs less utilities			1,666,100	7.00
Administrative, 10% of operating labor			84,900	0.36
Marketing, 10% of sales revenue			154,200	0.65
Total indirect costs			12,662,900	53.18
Gross average annual revenue requirements			25,354,400	106.48
Byproduct Sales Revenue				
Sulfur	38,550 short tons	40.00/short ton	(1,542,000)	(6.48)
Subtotal byproduct sales revenue			(1,542,000)	(6.48)
Total average annual revenue requirements			23,812,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/short ton S removed	$/short ton S recovered
Equivalent unit revenue requirements	6.80	15.87	0.76	598.30	617.70

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a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 39,800 short tons/yr.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $38,383,000; total depreciable investment, $72,333,000; and total capital investment, $74,624,000.

TABLE A-93

CITRATE PROCESS 500 MW NEW COAL-FIRED POWER UNIT 3.5% S IN COAL 90% REMOVAL REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 74624000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	NET REVENUE, $/TON SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	39800	38500	40.00	31772300	1540000	30232300	30232300
2	7000	31500000	1500000	39800	38500	40.00	31357600	1540000	29817600	60049900
3	7000	31500000	1500000	39800	38500	40.00	30942900	1540000	29402900	89452800
4	7000	31500000	1500000	39800	38500	40.00	30528200	1540000	28988200	118441000
5	7000	31500000	1500000	39800	38500	40.00	30113500	1540000	28573500	147014500
6	7000	31500000	1500000	39800	38500	40.00	29698800	1540000	28158800	175173300
7	7000	31500000	1500000	39800	38500	40.00	29284100	1540000	27744100	202917400
8	7000	31500000	1500000	39800	38500	40.00	28869400	1540000	27329400	230246800
9	7000	31500000	1500000	39800	38500	40.00	28454700	1540000	26914700	257161500
10	7000	31500000	1500000	39800	38500	40.00	28039900	1540000	26499900	283661400
11	5000	22500000	1071400	28500	27500	40.00	23896000	1100000	22796000	306457400
12	5000	22500000	1071400	28500	27500	40.00	23481300	1100000	22381300	328838700
13	5000	22500000	1071400	28500	27500	40.00	23066600	1100000	21966600	350805300
14	5000	22500000	1071400	28500	27500	40.00	22651900	1100000	21551900	372357200
15	5000	22500000	1071400	28500	27500	40.00	22237200	1100000	21137200	393494400
16	3500	15750000	750000	19900	19300	40.00	18942900	772000	18170900	411665300
17	3500	15750000	750000	19900	19300	40.00	18528200	772000	17756200	429421500
18	3500	15750000	750000	19900	19300	40.00	18113500	772000	17341500	446763000
19	3500	15750000	750000	19900	19300	40.00	17698800	772000	16926800	463689800
20	3500	15750000	750000	19900	19300	40.00	17284100	772000	16512100	480201900
21	1500	6750000	321400	8500	8300	40.00	12810600	332000	12478600	492680500
22	1500	6750000	321400	8500	8300	40.00	12395900	332000	12063900	504744400
23	1500	6750000	321400	8500	8300	40.00	11981200	332000	11649200	516393600
24	1500	6750000	321400	8500	8300	40.00	11566500	332000	11234500	527628100
25	1500	6750000	321400	8500	8300	40.00	11151800	332000	10819800	538447900
26	1500	6750000	321400	8500	8300	40.00	10737100	332000	10405100	548853000
27	1500	6750000	321400	8500	8300	40.00	10322400	332000	9990400	558843400
28	1500	6750000	321400	8500	8300	40.00	9907700	332000	9575700	568419100
29	1500	6750000	321400	8500	8300	40.00	9493000	332000	9161000	577580100
30	1500	6750000	321400	8500	8300	40.00	9078300	332000	8746300	586326400
TOT	127500	573750000	27321000	725000	702000		814406400	28080000	586326400	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER TON OF COAL BURNED							22.49	1.03	21.46	
MILLS PER KILOWATT-HOUR							9.64	0.44	9.20	
CENTS PER MILLION BTU HEAT INPUT							107.09	4.90	102.19	
DOLLARS PER TON OF SULFUR REMOVED							847.46	38.73	808.73	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							222040100	10936300	211103800	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER TON OF COAL BURNED							20.85	1.03	19.82	
MILLS PER KILOWATT-HOUR							8.94	0.44	8.50	
CENTS PER MILLION BTU HEAT INPUT							99.28	4.89	94.39	
DOLLARS PER TON OF SULFUR REMOVED							785.70	38.69	747.01	

TABLE A-94. CITRATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW existing oil-fired power unit, 2.5% S in oil; 0.8 lb SO_2/MBtu heat input allowable emission)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (pneumatic conveyor, feed storage bins)	230,000	0.9
Feed preparation (feeders, conveyor, tank, agitator, and pumps)	76,000	0.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	3,656,000	13.7
SO_2 absorption (four packed tower absorbers including presaturators and entrainment separators, tanks, agitators, and pumps)	10,865,000	40.6
Stack gas reheat (four direct oil reheaters)	726,000	2.7
SO_2 reduction (reactor tanks, aging tank, agitators, and centrifugal pumps)	678,000	2.5
S separation and removal (flotation tanks, rotary drum filters, pumps, slurry tank, heat exchanger, settling tank, heaters, flash drum, and compressor)	1,642,000	6.1
S storage and shipping (S receiving pit, heaters, S pump, and storage tank)	456,000	1.7
Sulfate purge (coolers, agitators, centrifuge, tanks, pumps, and refrigeration)	561,000	2.1
H_2S generation (battery limit plant)	3,728,000	13.9
H_2 generation (battery limit plant)	2,616,000	9.8
Subtotal	25,234,000	94.3
Services, utilities, and miscellaneous	1,514,000	5.7
Total direct investment	26,748,000	100.0
Indirect Investment		
Engineering design and supervision	2,529,000	9.5
Architect and engineering contractor	632,000	2.4
Construction expense	3,825,000	14.3
Contractor fees	1,167,000	4.4
Total indirect investment	8,153,000	30.6
Contingency	6,980,000	26.0
Total fixed investment	41,881,000	156.6
Other Capital Charges		
Allowance for startup and modifications	4,188,000	15.6
Interest during construction	5,026,000	18.8
Total depreciable investment	51,095,000	191.0
Land	39,000	0.1
Working capital	1,308,000	5.8
Total capital investment	52,442,000	196.9

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a. Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by direct oil reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for flyash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-95. CITRATE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW existing oil-fired power unit, 2.5% S in oil;
0.8 lb SO_2/MBtu heat input allowable emission)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	1,160 tons	90.00/ton	104,400	0.65
Citric acid	100 tons	1,340.00/ton	134,000	0.83
Natural gas	462,800 kft^3	3.50/kft^3	1,619,800	10.07
Catalyst			9,300	0.06
Total raw materials cost			1,867,500	11.61
Conversion costs				
Operating labor and supervision	64,525 man-hr	12.50/man-hr	806,600	5.01
Utilities				
Fuel oil (No. 6)	2,676,600 gal	0.40/gal	1,070,600	6.65
Steam	240,710 MBtu	2.00/MBtu	481,400	2.99
Process water	1,178,900 kgal	0.06/kgal	70,700	0.44
Electricity	48,688,000 kWh	0.029/kWh	1,412,000	8.78
Maintenance				
Labor and material			1,604,900	9.97
Analyses	10,100 man-hr	17.00/man-hr	171,700	1.07
Total conversion costs			5,617,900	34.92
Total direct costs			7,485,400	46.52
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			3,270,100	20.32
Average cost of capital and taxes at 8.6% of total capital investment			4,510,000	28.02
Overheads				
Plant, 50% of conversion costs less utilities			1,291,600	8.03
Administrative, 10% of operating labor			80,700	0.50
Marketing, 10% of sales revenue			60,700	0.38
Total indirect costs			9,213,100	57.25
Gross average annual revenue requirements			16,698,500	103.77
Byproduct Sales Revenue				
Sulfur	15,170 short tons	40.00/short ton	(606,800)	(3.77)
Subtotal byproduct sales revenue				
Total average annual revenue requirements			16,091,700	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/short ton S removed	$/short ton S recovered
Equivalent unit revenue requirements	4.60	3.02	0.50	1,042.88	1,060.76

a. Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 25 yr.
Power unit on-stream time, 7,000 hr/yr.
Oil burned, 5,324,100 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
S removed, 15,430 short tons/yr.
Investment and revenue requirement for removal and disposal of flyash excluded.
Total direct investment, $26,748,000; total depreciable investment, $51,095,000; and total capital investment, $52,442,000.

TABLE A-96

CITRATE PROCESS 500 MW EXISTING OIL-FIRED POWER UNIT 2.5% S IN OIL REGULATED CO. ECONOMICS

FIXED INVESTMENT: $ 52442000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	NET REVENUE, $/TON SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	5324100	15400	15200	40.00	21207900	608000	20599900	20599900
7	7000	32200000	5324100	15400	15200	40.00	20856400	608000	20248400	40848300
8	7000	32200000	5324100	15400	15200	40.00	20504900	608000	19896900	60745200
9	7000	32200000	5324100	15400	15200	40.00	20153300	608000	19545300	80290500
10	7000	32200000	5324100	15400	15200	40.00	19801800	608000	19193800	99484300
11	5000	23000000	3802900	11000	10800	40.00	17248700	432000	16816700	116301000
12	5000	23000000	3802900	11000	10800	40.00	16897100	432000	16465100	132766100
13	5000	23000000	3802900	11000	10800	40.00	16545600	432000	16113600	148879700
14	5000	23000000	3802900	11000	10800	40.00	16194100	432000	15762100	164641800
15	5000	23000000	3802900	11000	10800	40.00	15842500	432000	15410500	180052300
16	3500	16100000	2662000	7700	7600	40.00	13775600	304000	13471600	193523900
17	3500	16100000	2662000	7700	7600	40.00	13424100	304000	13120100	206644000
18	3500	16100000	2662000	7700	7600	40.00	13072500	304000	12768500	219412500
19	3500	16100000	2662000	7700	7600	40.00	12721000	304000	12417000	231829500
20	3500	16100000	2662000	7700	7600	40.00	12369500	304000	12065500	243895000
21	1500	6900000	1140900	3300	3300	40.00	9560200	132000	9428200	253323200
22	1500	6900000	1140900	3300	3300	40.00	9208700	132000	9076700	262399900
23	1500	6900000	1140900	3300	3300	40.00	8857200	132000	8725200	271125100
24	1500	6900000	1140900	3300	3300	40.00	8505600	132000	8373600	279498700
25	1500	6900000	1140900	3300	3300	40.00	8154100	132000	8022100	287520800
26	1500	6900000	1140900	3300	3300	40.00	7802600	132000	7670600	295191400
27	1500	6900000	1140900	3300	3300	40.00	7451000	132000	7319000	302510400
28	1500	6900000	1140900	3300	3300	40.00	7099500	132000	6967500	309477900
29	1500	6900000	1140900	3300	3300	40.00	6748000	132000	6616000	316093900
30	1500	6900000	1140900	3300	3300	40.00	6396400	132000	6264400	322358300
TOT	92500	425500000	70354000	203500	201000		330398300	8040000	322358300	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST										
DOLLARS PER BARREL OF OIL BURNED							4.70	0.12	4.58	
MILLS PER KILOWATT-HOUR							7.14	0.17	6.97	
CENTS PER MILLION BTU HEAT INPUT							77.65	1.89	75.76	
DOLLARS PER TON OF SULFUR REMOVED							1623.58	39.51	1584.07	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS							135047900	3637700	131410200	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT										
DOLLARS PER BARREL OF OIL BURNED							4.24	0.12	4.12	
MILLS PER KILOWATT-HOUR							6.44	0.17	6.27	
CENTS PER MILLION BTU HEAT INPUT							70.04	1.88	68.16	
DOLLARS PER TON OF SULFUR REMOVED							1464.73	39.46	1425.27	